STATE OF MAINE
PUBLIC UTILITIES COMMISSION

Docket No. 2007-215

September 14, 2007

CENTRAL MAINE POWER COMPANY
Chapter 120 Information (Post ARP 2000 Transmission and Distribution Utility Revenue Requirements and Rate Design, and Request for Alternative Rate Plan

BENCH ANALYSIS

I. SUMMARY

On December 31, 2007, Central Maine Power Company's Alternative Rate Plan (ARP 2000) will expire. Central Maine Power Company (CMP or Company) has proposed that the Commission adopt a new seven-year ARP, referred to as ARP 2008, at the conclusion of the current ARP. As part of its proposal, CMP is recommending that current rates not be changed at the conclusion of the ARP and that for purposes of calculating revenue requirements in this matter that the Commission add back $8.8 million of merger savings in revenue requirements to allow recovery of Energy East's acquisition premium. The Company has also proposed that as part of its ARP 2008 plan the Company will invest in Automated Meter Infrastructure (AMI) equipment and adopt a Reliability Improvement Program (RIP) to improve service reliability. The Company proposes that the ARP 2008 be changed annually based on an inflation minus productivity offset which will be 0.25% during the first two years of the ARP 2008 and 0.5% during the remainder of the ARP.

By way of this Bench Analysis, the Advisory Staff (Staff) provides its initial recommendations and analysis. Based on the information available to Staff to date, the Staff recommends that the Commission reject the Company's proposal and not adopt a successor ARP at this time. The Staff's recommendation against the adoption of an

ARP at this time is based on the number of uncertainties surrounding the Company's service reliability, the timing and amount of investments to be made to address reliability issues and install AMI and the proposed change in the Company's corporate ownership.

Based on our analysis a 16.91% reduction in rates, or $39.6 million in revenues, is warranted at the conclusion of the ARP to ensure that CMP's rates satisfy the just and reasonable requirements of 35-A M.R.S.A. § 301. This overall recommendation is based on a 9.8% return on equity and our subsidiary recommendations that the Commission not adopt CMP's AMI proposal at this time, that the Commission not accept CMP's proposed acquisition premium adjustment, and that the Commission approve in part and reject in part CMP's RIP proposals.

Should the Commission conclude that continuation of alternative regulation is appropriate at the expiration of ARP 2000, the Staff has put forward an alternative plan for consideration by the Commission which attempts to address the Staff's concerns. The Staff's plan would be for five years, would include a 1.75% productivity offset. The measurement would also include additional Service Quality Index (SQI) metrics from those proposed by CMP to address some of the Staff's reliability concerns.

II. BACKGROUND

A. Corporate Structure

On June 15, 1999, CMP announced that it had entered into a proposed merger agreement with Energy East Corporation Inc. (Energy East). The merger resulted in a cash payment to shareholders of $29.50 per share. This represented approximately a $306 million premium over CMP's market value at the time.

As part of the merger case, Energy East requested that the Commission affirm in its order approving the merger that Energy East would be accorded a reasonable opportunity to seek recovery of the premium from net synergies achieved by the merger. The Commission approved the merger by Order dated January 4, 2000. *CMP Group, Inc. et. al., Request for Approval of Reorganization and of Affiliated Interest Transactions,* Docket No. 99-411. In its order, the Commission stated that it would not rule out allowing Energy East to include some level of the acquisition premium upon a clear and persuasive showing that the savings resulting from the merger itself (and not from some other cause) exceed the costs imposed by the merger.

On August 1, 2007, CMP and Maine Natural Gas filed a petition for approval of the proposed sale of Energy East to Iberdrola, S.A. (Iberdrola) a Spanish corporation. Under the terms of the proposed sale, Iberdrola would purchase all of Energy East's outstanding shares for $28.50 per share or $4.5 billion. This purchase price represents approximately a $1 billion premium over Energy East's market value at the time of the sale agreement. The request for approval of the proposed sale to Iberdrola is currently pending in Docket No. 2007-355.

B. CMP's Alternative Rate Plans

In December 1993, following a series of rate cases and rate increases, the last of which involved a review of CMP's management, the Commission concluded that it should consider moving from traditional cost of service/rate of return regulation to a multi-year price cap approach. *Central Maine Power Company, Proposed Increase in Rates,* Docket No. 92-345, Order at 125 (Dec. 14, 1993). After nearly a year of litigation, the Commission approved a Stipulation which established a 5-year Alternative

Rate Plan (ARP 95) for CMP. *Central Maine Power Company, Proposed Increase in Rates,* Docket No. 92-345 (Phase II), Detailed Opinion and Subsidiary Findings (Jan. 10, 1995). ARP 95 allowed CMP's rates to change based on changes to the rate of inflation, measured by the GDP-PI, less a productivity offset, and further adjusted for mandated costs, earnings sharing and service quality penalties.

During the course of ARP 95, the Legislature passed the Electric Industry Restructuring Act, 35-A M.R.S.A. § 3201 *et. seq.* which, effective March 1, 2000, deregulated generation services and provided Maine consumers with direct retail access to the generation market. Pursuant to the provisions of 35-A M.R.S.A. 3208, the Commission initiated an investigation of CMP's Transmission and Distribution (T&D) revenue requirements, stranded costs and rate design. On February 24, 2000, we issued an Order which set CMP's T&D rates effective March 1, 2000. *Public Utilities Commission, Investigation of Central Maine Power Company's Stranded Costs, Transmission and Distribution Utility Revenue Requirements and Rate Design,* Docket No. 97-580 (Phase II-B), Order Approving Stipulation (Feb. 24, 2000).[1]

On September 19, 1999, CMP filed a request for a successor ARP entitled ARP 2000. On November 16, 2000, the Commission issued its decision in *Central Maine Power Company, Request for Approval of Alternative Rate Plan (Post Merger)*

[1] In *Maine Public Utilities Commission, Investigation of Retail Electric Transmission Services and Jurisdictional Issues,* Docket No. 99-185, Order Approving Stipulation (Central Maine Power Company) August 28, 2000, we recognized that the Federal Energy Regulatory Commission (FERC) had asserted jurisdiction over transmission service once a state unbundled generation service from regulated retail service. Therefore, we unbundled transmission service costs from the T&D revenue requirement we had established in Docket No. 97-580 and established rates for distribution services only, including stranded costs.

"ARP 2000", Docket No. 99-666, Order Approving Stipulation (Nov. 16, 2000) (the "ARP 2000 Order") and thus approved a second alternative rate plan (ARP) for Central Maine Power Company (CMP). Under the terms of the Commission's Order, ARP 2000 took effect on January 1, 2001 and will run through December 31, 2007. ARP 2000, which applies only to CMP's distribution delivery service, provides for annual rate changes to occur on July 1 of each year of the ARP based on a rate change formula similar to ARP 95's formula. The productivity offsets established for the ARP 2000 plan were as follows:

Year of Price Change	Productivity Offset
2001	Equal to Inflation
2002	2.00%
2003	2.25%
2004	2.75%
2005	2.75%
2006	2.75%
2007	2.90%

The earnings sharing provisions agreed to in the Stipulation were identical to those proposed in the Staff's Bench Analysis in that case. Thus, there is no top-end earnings sharing and revenue deficiencies below a 5.2% Return on Equity (ROE) from the calendar year prior to the price change are to be shared 50/50 between shareholders and ratepayers. The ARP 2000 Stipulation does not discuss or address Energy East's acquisition premium.

On December 7, 2005, the OPA filed a Stipulation entered into between the OPA and CMP to extend ARP 2000 by three years, or until December 31, 2010. According to the letter filed with the Commission, the Stipulation was the result of bilateral negotiations between CMP and the OPA and was the end product of

discussions that began on October 14, 2005.[2] The ARP Extension Stipulation proposed to continue CMP's current ARP with the following four significant additions: (1) an additional productivity offset of 0.5 percentage points for July 2006 with productivity offsets averaging 2% for 2008, 2009 and 2010;[3] (2) limitations on CMP's promotion of the consumption of electricity at, or near, its winter and summer peak demand periods, as well as collaboration with Efficiency Maine in order to help with its efficiency efforts; (3) an increase in available funding for low-income Electric Lifeline Program (ELP) for CMP's customers from $4.0 million to $6.2 million annually;[4] and (4) the commitment by CMP to invest an incremental $25 million through 2010 in its distribution system in order to provide greater assurance of reliable electric service. In addition, the ARP Extension Stipulation provided that any additional operating and maintenance expenses solely resulting from new distribution reliability requirements arising out of the Commission's reliability investigation of CMP's distribution system, Docket No. 2005-705, would be deferred with carrying costs using CMP's overall cost of capital.

During its June 2, 2006 deliberative session, the Commission concluded that the ARP Extension Stipulation, as proposed, would not produce just and reasonable rates during the term of the ARP and, therefore, would not be in the public interest. Specifically, the Commission found that over the course of the extension period, the Stipulation would result in CMP overearning in the range of $20 million,

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[2] The IECG filed an executed signature page joining the Stipulation on January 5, 2006.

[3] The productivity offset for 2007 would remain as set in the current ARP.

[4] The funding for the increase in ELP spending would be provided by CMP's ratepayers.

accepting CMP's assumptions, to approximately $80 million, accepting the Advisory Staff's assumptions which the Commission generally found to be reasonable and that while the Stipulation would produce a certain level of rate stability, which all else equal may be seen as being beneficial, the other purported benefits of the Stipulation were either minimal or non-existent. The Commission also found troubling the fact that the Stipulation, as proposed, would extend the ARP and the ARP's existing service quality protection provisions prior to the completion of the review being conducted of CMP's distribution system and maintenance practice and procedures (also known as the grid study) in Docket No. 2005-705, discussion below, and would also provide a mechanism for the recovery of costs which result from implementing the grid study's results without knowing what the amount or cause of such costs were.

Rather than reject the Stipulation outright, the Commission proposed a set of conditions which, if accepted by the parties, would allow approval of the Stipulation. On June 7, 2006, the Stipulating parties filed a request that this matter be dismissed without prejudice which was approved by the Commission.

C. Grid Reliability Studies

During its 2003 session, the Legislature passed an Act to encourage Energy Efficiency and Security. The Act directed the Commission to investigate regulatory mechanisms and rate designs that provide incentives for transmission and distribution utilities to promote energy efficiency and the security and robustness of the electric grid. As required by the Act, the Commission submitted a report to the Joint Standing Committee on Utilities and Energy (the U&E Committee) on February 1, 2004. During the presentation of the Commission's Report, the U&E Committee indicated that

it was interested in the continued examination of certain issues associated with grid reliability and security. In a letter to the Commission dated February 23, 2004, the U&E Committee requested that as part of this follow-up examination, the Commission specifically quantify "the safety margin of the grid system, including such indicators as maintenance activity, and analyze how the margin may have changed over time, particularly as the result of alternative rate plans and restructuring."

On June 17, 2005, the Commission issued its Final Report in response to the U&E Committee's request. In its Final Report, the Commission concluded that CMP was maintaining its distribution system to meet the requirements of its ARP, and therefore, on a system level, CMP's distribution system was adequate. However, the Commission expressed concern about the disparity between CMP's worst performing circuits and its overall SAIFI and CAIDI performance and about the nature and scope of CMP's distribution system maintenance and improvement program. This concern was heightened by CMP's previous suspension of its distribution inspection program, the aging of CMP's plant, the increase in the number of outages, and what appeared to be inadequate record-keeping in CMP's distribution planning and maintenance operations.

The Commission, therefore, concluded that an additional review of the operation and maintenance of CMP's distribution system by an independent party was appropriate. The Commission noted that this examination would not only shed light on CMP's maintenance practices but might provide an indication of the effectiveness of the current ARP's performance standards and, thus, would be particularly timely given the current ARP's expiration in 2007.

On December 13, 2005, the Commission initiated an inquiry to serve as the vehicle to conduct this further review. *Maine Public Utilities Commission, Review of Central Maine Power Company's Distribution System and Distribution Practices and Procedures,* Docket No. 2005-705, Notice of Inquiry (Dec. 13, 2005). Following the issuance of an RFP and an extensive evaluation procedure, which included feedback from CMP, the Commission engaged Williams Consulting Incorporated (Williams or WCI) to act as the independent party to conduct the review. WCI's review included:

- Interview meetings with 29 CMP management, technical, and field personnel
- Development and analysis of 182 data requests to CMP
- Development of a statistically valid sample designed to represent the overall electric distribution system
- Independent physical field inspections of 16 circuits, including 2,597 poles, to assess the condition of the overall distribution system
- A review and evaluation of CMP's distribution record keeping practices
- Review and evaluation of the Company's Field Operating Procedures related to distribution system operation and maintenance procedures and practices
- Periodic meetings with MPUC Staff, Commissioners, and CMP management in Augusta, Maine

On February 26, 2007, WCI submitted its "CMP Distribution Plant Evaluation – Final Report" to the Commission. Based on its study, WCI found that:

- CMP has achieved a high level information system integration and development of support tools. Based on WCI's experience, it believed that CMP was among the leaders in the utility industry.

- CMP's stated approach to reliability performance was to "manage to the ARP targets." While this may be understandable from a cost perspective it virtually assures that CMP's reliability performance will not improve.
- The current ARP targets for CAIDI and SAIFI appear to be a protective minimum or floor intended to assure reliability performance does not deteriorate. These annual targets have always been met by CMP and have been adjusted several times in the recent past to accommodate changes in reporting levels and exclusions. The current ARP targets are measured at the Company level and do not provide targets at the Service Center or circuit level.
- Although within ARP reliability targets, CMP's reliability performance falls into the third quartile (i.e., poorer than average performance) for CAIDI, as compared to the Institute of Electrical and Electronic Engineers (I.E.E.E.) survey of U.S. utilities. Further, CMP's SAIFI falls within the fourth quartile (i.e., worst performers), and has been increasing (getting worse) during the period 2001-2005.
- CMP identifies its 10 worst performing circuits annually and focuses efforts to improve their performance so that they fall from the list during the year following remediation. However, a number of worst performing circuits remained on the list in subsequent years. Additionally, these circuits were selected based on their "contribution" to system-wide SAIFI and CAIDI.[5] While remediation efforts for

[5] System-wide SAIFI and CAIDI are based on the total number of customers for the system in the denominator of the calculation; while the circuit's connected customers is part of the numerator calculation. So a circuit's "contribution" to system-wide figures will assign a higher contribution for those circuits with higher number of

these circuits will bring about overall system-level reliability improvement, there is no guarantee that worst performing circuits measured at the Service Center[6] or circuit level are being adequately addressed.

- CMP has significantly reduced the percentage of outages caused by animal contact through its pro-active program of installing animal guards on distribution transformers. However, CMP's tree related outages are among the highest in the industry. During 2005, they accounted for 42.3% of the outages compared to Edison Electric Institute's (IEE) U.S. average of 21%. This clearly indicates that vegetation management presents significant improvement opportunities.
- Tree related outages appear to be more frequent in areas with lower customer density. This implies that the Company focuses its vegetation management and overhead lines maintenance resources on its more heavily populated service areas. Given the ARP targets and measurements, this is not surprising.
- CMP's overhead distribution plant appears to be in good mechanical and electrical condition. CMP has undertaken a number of pro-active programs to improve the performance of the system, such as the focused animal guard program.
- CMP does not employ a cycle trim program. CMP sets an informal goal of trimming 15% to 20% of its 3-phase circuits annually. However, these circuits only comprise 20% of the system. The remaining 80% are planned for trim on a

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connected customers than for those with fewer connected customers, assuming the same number of outages and restoration times.

[6] CMP manages its distribution system through 11 Service Centers geographically spread through its service area at Portland, Alfred, Augusta, Bangor, Brunswick, Dover Fairfield, Farmington, Lewiston, Portland, Rockland and Skowhegan.

reactive basis. While the arborists have good analytical tool to plan the trim program, the level of funding for distribution vegetation management is the constraining element. Based on WCI's field observations and professional experience, the state of vegetation encroachment was found to be less than satisfactory.

- Annual distribution vegetation management program budgets and actual expenditures have remained relatively flat over the past five years, while tree-related outages have increased each year.
- Based on its physical condition inspection results, WCI found that CMP faced a significant risk of outages due to vegetation encroachment on the overhead primary distribution system. The risk includes events such as tree fires, momentary customer interruptions, flickering lights, damage to customers' equipment, hazard to the general public, and increased recloser operations. This later event would require CMP to inspect and/or replace reclosers more frequently. Between 12.7% ad 19% of CMP's circuits have vegetation in direct contact with the conductor. Another 15.8% to 23.8% of the circuits have vegetation within 3 feet, which is likely to pose a risk to the system within one year.

III. CMP'S REQUEST TO SHARE MERGER SAVINGS IN RECOGNITION OF THE ACQUISITION PREMIUM

A. Energy East Acquisition of CMP Group

Until the late 1990's the predecessor to Energy East Corporation was a combination gas and electric utility known as New York State Electric and Gas (NYSEG). Following industry restructuring in New York, NYSEG sold its generation facilities, and adopted the holding company structure and the Energy East name. Shortly thereafter, Energy East began acquiring other northeastern utilities, beginning with the announcement of a deal to acquire CMP Group, Inc. (CMP Group) on June 15, 1999.[7]

On the day before the merger was announced, the share price of CMP Group was $20.0625 per share. At the agreed upon price for the acquisition of $29.50 with 32,442,552 shares outstanding, the market premium was $9.4375 per share, or $306.2 million. At the same time, CMP Group's book equity value per common share was roughly $17.00 per share ($16.69 on 3/31/99 and $17.03 on 6/30/99).

At the time of the acquisition, CMP Group was comprised of several subsidiaries, the largest of which was the company's transmission and distribution utility, Central Maine Power Company (CMP). Other subsidiaries of note included Northeast Optical Network, Inc. (NEON), a telecommunications joint venture with Northeast Utilities, Union Water Power Company which itself had an engineering subsidiary and a real estate holding arm, MEPCO, a joint venture owning a transmission

[7] Shortly after the announcement of the CMP acquisition in June 1999, Energy East announced merger deals with Connecticut Natural Gas Company, Southern Connecticut Gas Company and Berkshire Energy Group. Several years later, Energy East acquired RGS Corporation (formerly known as Rochester Gas & Electric Corporation).

line connecting eastern Maine with New Brunswick, and Maine Natural Gas Company, a start-up natural gas distribution company.

B. Distinction between "Goodwill" & "Acquisition Premium"

There is ambiguity in CMP's testimony as to precisely what the Company means when it refers to the term "acquisition premium." CMP witnesses Stinneford and Dumais define the premium as:

> …Energy East paid an amount in excess of the book value of CMP's common stock… This excess over book value is called the acquisition premium. The acquisition premium totaled $331.1 million, of which $11.3 million was amortized in 2000 and 2001 under prior accounting requirements. The balance of the acquisition premium at the end of 2006 is $319.7 million.

Stinneford/Dumas Testimony at 24. CMP witness Schnitzer defines "acquisition premium" differently. He states that acquisition premium should be measured as the "premium Energy East paid over the market value of CMP's stock just prior to the merger announcement." Mr. Schnitzer stated: "Energy East acquired CMP in 2000 for $29.50 per share, or $955 million. This represents approximately a $300 million premium above the market value of the equity of CMP prior to the announcement of the transaction." (Schnitzer testimony at 1)

Henceforth, we will refer to the Stinneford/Dumais definition of the acquisition premium as the "Goodwill premium" and the Schnitzer definition as the "Market Value premium." Prior to any allocation to CMP Group subsidiaries and NYSEG, the magnitude of the acquisition premium is similar whether the Goodwill premium at $319.7 million or the Market premium method at $300 million is considered. However although these two numbers are similar on their face, it is important to evaluate which method is the more theoretically appropriate reference point. Furthermore, even though

the numbers are similar before making allocations of the acquisition premium to other companies, the calculations may diverge as portions are allocated to the host company and portions are allocated to the other subsidiaries of the former CMP Group.

C. CMP's Ratemaking Adjustment Related To The Acquisition Premium.

CMP requests, in calculating the starting point revenue requirement, and in performing the financial analysis upon which the Commission will determine whether an ARP will produce rates that are just and reasonable, that "the Commission include a cost of service adjustment equal to one-half of the net operational savings that have been achieved as a direct result of the merger." (Stinneford/Dumas Testimony at 26) Since CMP calculates the net O&M savings from the merger to be $21 million per year for the entire T&D company, and $18 million per year for the distribution portion of its business, it proposes an annual adjustment to O&M expenses of 50% of the approximate $18 million, or $8.8 million per year.

Mr. Stinneford and Mr. Dumas stated that CMP reduced its costs after the merger by reducing its number of employees, which was accomplished by consolidating management, accounting, finance, IT and other functions in newly-formed affiliated companies that perform these functions for the entire family of Energy East subsidiaries. Similarly, CMP reduced its non-labor costs by consolidating its purchasing of goods and services through other Energy East affiliates. They estimated CMP's merger-related labor savings by estimating the total costs related to the jobs that were eliminated at CMP in these areas, and subtracting the costs of those jobs that CMP would have eliminated because of efficiency that would have been achieved by a stand-alone CMP. They estimate the stand-alone efficiency by assuming that the 1% base productivity

factor testified to by its witness in the ARP 2000 proceeding (Dr. Malkholm) and set by the Commission in ARP 1995 would have been the efficiency achieved absent the merger. At the request of Mr. Schnitzer, they make an estimate of the net savings assuming that 1.5% is the correct stand-alone productivity. From that "net merger savings", they subtract the Energy East affiliate expenses incurred by CMP for these functions.

They estimate the non-labor merger savings by estimating the savings achieved from the consolidated purchase efforts, and adding the costs of goods and services that a stand-alone CMP would have incurred but that the Energy-East-owned CMP does not, like certain insurance and corporate governance expenses. Mr. Schnitzer takes these estimates and concludes that since the merger was completed in 2000, the merger produced $96 million in distribution system savings if CMP would have achieved the assumed 1% of productivity savings without the merger. He concludes that CMP saved $85 million if the stand-alone CMP would have achieved 1.5% productivity.

Mr. Schnitzer similarly assumes that a stand-alone CMP ARP would have yielded a productivity offset of 1%, or alternatively 1.5%. His assumption is reasonable, in his view, because 1) Dr. Malkholm opined that 1% was the proper base productivity factor in his ARP 2000 pre-filed testimony, 2) ARP 1995 had a productivity factor of 1%, and 3) the BHE 1998 ARP had a factor of 1.2%. Accepting his assumption about what a stand-alone ARP would look like, he concludes that ratepayers have received merger-related savings, because the merger-enhanced ARP 2000 stipulation productivity factors (between 2.0 and 2.9 each year) produced lower rates than would have been produced by the assumed stand-alone 1% or 1.5% productivity factors. His lower rates

calculation, in his view, demonstrates that ratepayers have received a vast majority of the merger savings estimated by Mr. Stinneford and Mr. Dumas. If the stand-alone CMP ARP would have yielded a 1% productivity factor, ratepayers have enjoyed lower rates in an amount that is 95% of the present value of the Stinneford/Dumas-estimated merger savings. At a 1.5% factor, ratepayers received 68% of the estimated savings. Because ratepayers have received either 68% or 95% of the merger savings to date, he concludes Energy East shareholders have only received 32% or 5%, depending on which of the assumed stand-alone productivity factors is used .

Mr. Schnitzer states that Energy East did not achieve these savings without investment and risk. He states that Energy East paid a premium of approximately $300 million above market value. In his opinion, a "continued opportunity [for Energy East shareholders] to share in merger savings is good public policy" and "a sharing of merger savings beyond the term of ARP 2000 was explicitly contemplated by the Commission". Schnitzer Testimony at 3. He concludes that CMP's proposed annual cost-of-service adjustment of $8.8 million is reasonable because ratepayers have received the lion's share of the merger savings and shareholders have received little.

D. Commission Order in Docket No. 99-411 Approving Energy East Acquisition of CMP Group

As CMP asserts that its proposal that Energy East share the merger-enabled savings with ratepayers is consistent with the Commission's Order approving the merger, it is helpful to review that Order in greater detail than CMP did in its filing. The Commission approved the merger acquisition in an Order dated January 4, 2000 in Docket No. 99-411, *Central Maine Power Group, Inc., Order,* Docket No. 99-411 (Jan. 4, 2000) (hereinafter referred to as the "*Merger Order*").

In the *Merger Order*, the Commission approved the Energy East acquisition, subject to various conditions. Ironically, many of the conditions were imposed to ensure that the benefits of the merger outweighed the risks, made necessary because Energy East claimed it had not performed any detailed cost savings analysis and did not have any plan as to the general magnitude of, or how to achieve, the savings.

The Commission opined that, in considering the merger from the perspective of ratepayers, the greatest risks and benefits involve the impact of the merger on rates. The rate impact revolved around two issues, neither of which were directly involved in the merger proceeding: the ratemaking treatment of the acquisition premium and the next incentive rate plan for CMP. The Commission did note that Energy East asked the Commission to affirm in its order approving the merger that Energy East will be accorded a reasonable opportunity to recover the acquisition premium through net synergies achieved by the merger. *Id.* at 17.

In discussing acquisition premiums, the Commission noted the dilemma caused by them. If the premium were automatically included in rates, then the merger offering price will rise to the point where rates are set at the same level that an unregulated monopoly firm would charge its customers. On the other hand, a blanket denial of recovery of a merger premium could lead to higher costs and rates if merger synergies are not obtained because the blanket denial may inhibit mergers from occurring. Accordingly, in *dicta* in the order approving the merger of Bangor

Hydro-Electric Company and Stonington and Deer Isle Power Company, the Commission stated that:

> If the record shows that the customers of the surviving utility will realize benefits of efficiency savings, then the utility might be entitled to recover some of its costs in excess of net book value.

Bangor Hydro-Electric Company and Stonington & Deer Isle Power Company, Joint Application to Merge Property, Franchises and Permits and for Authority to Discontinue Service, *Order*, Docket No. 87-109, at 3 (Nov. 10, 1987) (the *Stonington Order)*.

In the *Merger Order*, the Commission stated that it continued to support the concept as expressed in *dicta* in the *Stonington Order*. The Commission noted, however, that the policy would not be easily put into practice. The Commission concluded its analysis by stating:

> To balance these conflicting concerns, we will not rule out allowing Energy East to include some level of the acquisition premium in a future rate request upon a *clear and persuasive showing* that the savings resulting from the merger itself (and not from some other cause) exceed the costs imposed by the merger. *In other words, the only portion of the savings from which shareholders can recoup any portion of the premium is the portion that would not have existed "but for" the merger.* If net efficiency savings from the merger can be demonstrated, we will allow recovery of the acquisition premium through rates subject to the following limitations:
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> (a) the acquisition premium will not be considered in any way where the effect of including the premium in any rate calculations would be to increase rates above levels that would exist absent the merger (in other words, there must be demonstrable benefits available to ratepayers sufficient to offset all merger related-costs); and
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> (b) Maine ratepayers receive a reasonable portion of the net savings from the merger.

We take this opportunity to offer some insight into how we would analyze a request to recover some or all of the acquisition premium. First, as we stated in *Stonington, to allow recovery of some or all of an acquisition premium, there must be a clear and demonstratable showing of net merger-related savings. That will not be an easy showing.* The record in this case contains numerous assertions, particularly by the Petitioners and Energy East, that efficiency gains are difficult to quantify before the fact, essentially because of the need to forecast the costs of the newly merged entity. Efficiency *gains may be similarly difficult to qualify after the fact, because we would have to compare the actual costs of the merged entity with the forecast or expected costs that would have been incurred had the merger not gone forward. This task will become increasingly difficult over time.* Energy East is proposing to amortize the acquisition premium over 40 years. Long before that, *within 5 or 10 years,*[8] *it may be impossible to develop any reasonable estimate of merger specific efficiencies. Thus, there will be an increasingly difficult burden on Energy East to demonstrate that savings are indeed the result of the merger as time passes.*

Second, once a reasonable estimate of merger savings has been developed, we would have to consider whether the Maine ratepayers should be responsible for any of the premium.*

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* A related issue which was not explored in this case is the question of whether any premium allowed in rates should be limited to the difference between the acquisition price and the market price of the stock immediately before the merger was publicly announced. This is sometimes referred to as the "control premium" because it represents the additional value, over the market price of the stock, which the acquiring firm paid to gain control and, therefore, to obtain any synergies. If a request for recovery of the premium were to come before us, we would also consider whether the control premium, rather than the total premium, was the appropriate measure. *See, e.g., Guidelines and*

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[8] An *Order **Correction*** in Docket No. 99-411 was issued on January 7, 2000 that corrected the January 4 Order. The January 4 Order had stated "within 15 or 10 years . . .".

> *Standards for Acquisition and Mergers of Utilities,* 155 P.U.R. 4th 320, 327 (Mass. D.P.U. 1994).

Merger Order at 19-20. (Footnote * in original, footnote 2 added, emphasis added).

Ultimately, the Commission stated that the record in the proceeding "brings us close to a finding that the evidence of both potential gain and potential harm is so amorphous that we cannot satisfy section 708." *Id.* at 22. However, the Commission approved the merger because it was satisfied that the merger created the potential for significant savings for CMP and thus significant benefits for CMP's ratepayers, and the Commission desired customers to have at least a chance to share those benefits. To protect ratepayers in the event merger savings failed to be attained, the Commission stated that in any proceeding for CMP after the merger:

> we will require that the rates charged customers be at least as low, and service quality at least as high, as could be expected of CMP absent the merger.

Merger Order at 22.

The Commission made two other noteworthy comments in the *Merger Order* about rates and incentive rate plans. Both were in regards to the incentive rate plan that was described in the merger approval docket but which was filed in Docket No. 99-666. In the first comment, the Commission noted that Energy East sought an incentive rate plan that was related to the acquisition premium in two ways. First, since its plan was for 7 years, Energy East asserted that rates would then be set largely ignoring any merger savings and CMP would use some or all of the savings to offset the acquisition premium. Second, under Energy East's proposal, the acquisition premium would be an explicit component of the earnings sharing formula. Energy East proposed that if actual earnings were above a dead band, a portion of the excess that might

otherwise go toward reducing rates (or reducing the size of a rate increase) would be used to offset the amortization of the acquisition premium. *Merger Order* at 19.

In the second noteworthy comment, the Commission mentioned that CMP proposed a productivity offset of 1% for 2001, rising at 0.25% per year until it reached 1.75% in 2004, and then stayed at that level through 2006, the last year of the plan. CMP suggested in the merger proceeding that the Commission should treat increases in productivity offset above 1%, the level of the offset in ARP 1995, as merger savings and therefore, by adopting the rate plan, the Commission could ensure that the merger would provide lower rates than would exist without the merger. The Commission responded to CMP's suggestion by stating that, as the specific ratemaking treatment was ruled outside the scope of the merger proceeding, it had not yet tested the premises of Energy East's proposed ARP. Therefore, the topic of the proper productivity offset for a stand-alone CMP had to be left to the proceeding opened to process CMP's filing seeking a performance based rate plan (Docket No. 96-666). *Merger Order* at 22.

E. <u>Commission Order in the ARP 2000 and Other ARP Proceedings.</u>

Mr. Schnitzer's analysis is premised on the assumption that the Commission would have imposed a productivity factor of 1% (or alternatively 1.5%) as part of an alternative rate plan for a stand-alone CMP in the ARP 2000 proceeding. Accordingly, a review of the Commission orders in the ARP 2000 proceeding (Docket No. 1999-666) and some earlier ARP decisions is useful in testing the reasonableness of Mr. Schnitzer's assumption.

The first extensive consideration of the proper components of a reasonable alternative rate plan actually occurred in Phase I of Docket No. 92-345, before any rate plan was actually adopted for CMP. During Phase I, the Commission asked the parties to consider alternative rate plans. CMP responded by proposing a price cap mechanism in Phase I. Various parties opposed CMP's proposal. Ultimately in the Phase I Order (*Order, Part II*, Docket No. 92-345, Dec. 14, 1993), the Commission stated that, while it was "comfortable with the broad outlines" of an ARP for CMP, the record was insufficient to impose an ARP at that time. *Id.* at 125. Instead, the Commission opened up a Phase II of the proceeding and encouraged CMP and the parties to Phase I to work to develop consensus on as many issues as they could. In order to assist the parties in achieving consensus, the Commission stated its views on various pieces of a price cap mechanism. The Commission described the productivity offset as the most significant issue in determining the specific characteristics of the rate plan. The Commission added that :

> A "stretch factor" to the productivity offset should be given serious consideration during negotiations in order to minimize risks to consumers, as well as to place more pressure on CMP to improve its cost efficiency. The productivity offset should be no less than one percent, ….

Id. at 137.

Ultimately the parties did negotiate a rate plan that resulted in ARP 1995, approved in the Phase II Orders of Docket No. 92-345. As described by Mr. Schnitzer, the general productivity factor in ARP 1995 was 1%. The actual formula reflected a QF factor of .375 to account for QF contracts that were not subject to inflation and were estimated to represent 37.5% of CMP's costs.

Mr. Schnitzer also cites the BHE 1998 ARP productivity factor of 1.2%. *Bangor Hydro-Electric, Proposed Increase in Rates,* Docket No. 97-116 (Feb. 9, 1998). In the BHE case, the Staff had supported a 1.2% productivity factor, plus a 0.3% stretch factor. The Commission imposed only a productivity factor without a stretch factor because of BHE's constrained financial circumstances at the time.

The third reason that Mr. Schnitzer uses to justify 1% as the proper productivity factor for a stand-alone CMP ARP is the prefiled testimony of CMP witness Jeffrey Malkholm in the ARP 2000 proceeding. Dr. Malkholm stated that 1% was an appropriate annual productivity factor in the absence of a merger. However, Dr. Malkholm's was not the only analysis in the ARP 2000 record. The OPA's witness recommended an average productivity factor of 2.5%, which Mr. Catlin described in his testimony in this case as including a base factor of 1.5%. The Advisory Staff recommended a productivity factor of 3%, which was composed of a base factor of 2% and a stretch factor of 1%. The Staff's 3% did not include a merger savings component per se, but its recommendation was based on an industry-wide analysis, not a CMP-specific one. Therefore, merger savings occurring throughout the industry would have been captured implicitly.

ARP 2000, of course, was implemented as an approved-stipulation. Accordingly, the Commission did not consider and choose among the competing productivity analyses. The productivity factor provided for in the Stipulation, however, was closer to the OPA and Staff analysis than Dr. Malkholm's.

It is worth noting that while the Stipulation was contested, the productivity offsets were not the source of the opposition. The Stipulation was opposed because it

did not provide for high-side earnings sharing. Unlike ARP 1995, ARP 2000 did not require a 50/50 split (between ratepayers and shareholders) for any earnings beyond a "dead-band" of 350 points above the allowed ROE. The no-high-side-earnings-sharing approach was first advanced by the Staff in its Bench Analysis. Allowing CMP to retain the earnings for all efficiency, whether from merger savings or otherwise, avoided more complicated provisions advanced by CMP that could have required distinguishing between merger savings and other efficiencies, and also that would have required resolution of the controversial issue as to the amount of the acquisition premium that related solely to the CMP T&D utility.

Indeed, in concluding that the stipulated result was reasonable, the Commission rejected the IEPM's argument that the retention of all high-side earnings violated the Merger Order's conditions concerning recovery of the acquisition premium. *Order Approving Stipulation* at 15. By doing so, the Commission implicitly recognized the advantage of the high-side-earning provision in relation to the acquisition premium as advanced by Staff in the Bench Analysis. In the rate plan itself, there is no provision for the recovery of the acquisition premium. However, the Commission observed that by exceeding the savings assumed by the productivity offsets, Energy East could apply these amounts to recovery of the premium. Thereby, ratepayers receive at least some of the merger benefits implicitly in the agreed-to productivity factors, whether Energy East achieved them or not, and Energy East received the opportunity to recover its acquisition premium without the controversial ratemaking issues of separating merger savings from other savings or calculation of the amount of the premium.

The other contested issue related to the length of the ARP. IEPM asserted that the ARP 2000 term of 7 years was too long. In the proceeding, both the OPA and Staff proposed a 5 year term. CMP asked for a 7 year term. The Commission stated that 5 years is not an upper bound for rate plan terms, even though ARP 1995 was for 5 years. *Id.* at 16. The Commission reasoned that the longer term could strengthen the incentives and provide greater price stability and reliability. *Id.* The Commission concluded its rejection of IEPM's arguments by stating:

> In addition, we note that in our order approving the Energy East/CMP merger we stated that it would be increasingly difficult over time to link cost savings to the merger and, therefore, to recover the acquisition premium. Docket No. 99-411, *supra.* at 20. Thus, to the extent that the IEPM is concerned about the recovery of the acquisition premium in rates, the longer term of the ARP here actually makes such an event less likely.

Id.

F. <u>CMP's Proposed Ratemaking Adjustment Is Not Reasonable.</u>

CMP's request relies on its conclusion that shareholders have received little benefit from the merger while ratepayers have received substantial amounts. CMP's analysis to support this conclusion consists of a three step calculation:

Step 1: Compute the cost savings achieved from the merger through assuming, among other things, that the number of non-union employees would decline by 1% per year but for the merger.

Step 2: Compute the amount of merger savings recovered by ratepayers independently of step 1 above by assuming that the Commission

would have imposed a 1% productivity factor in a stand-alone CMP ARP.[9]

Step 3: Compute the investor savings through subtracting the total savings in step 1 from the recoveries in step 2.

1. <u>CMP's Proposal Does Not Satisfy the Criteria Established in the *Merger Order*.</u>

Even ignoring for the moment that CMP's calculation of the acquisition premium is likely overstated, CMP has not made a *clear and persuasive showing* of the "but for" merger savings that CMP has achieved, as required by the *Merger Order.* Likewise, CMP has not made a clear and persuasive showing of the amount of savings that ratepayers or shareholders have received by the operation of ARP 2000.

Both Step 1 and Step 2 rely on the same assumption: absent the merger, productivity would have been 1%. In both instances, CMP asserts that the assumption is shown to be reasonable because of Dr. Malkhom's testimony in the ARP 2000 proceeding, and the ARP 1995 productivity factor of 1%. In his Step 2 analysis, Mr. Schnitzer adds the 1998 BHE ARP productivity factor of 1.2% as justification In neither instance, however, has CMP satisfied the *Merger Order* criteria of making a clear and persuasive showing of the "but for" merger savings.

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[9] In both steps 1 and 2, Mr. Schnitzer directs an alternative 1.5% factor be used in the calculation.

The Commission warned CMP that a *clear and convincing showing* would be increasingly difficult over time, perhaps even impossible after 5 to 10 years. Yet CMP supports its assumption that a stand-alone CMP would have achieved 1% savings in non-union labor by simply citing Dr. Malkholm's conclusion from his ARP 2000 testimony. CMP offers no reason why a 2000 study by its own expert, which was not put to the test of a fully litigated Commission process, is valid to predict what CMP could have achieved as a stand-alone company from 2000 to 2007. Other testimony and analysis in the ARP 2000 docket arrived at different conclusions and criticized Dr. Malkholm's study. CMP makes no attempt to demonstrate that Dr. Malkholm is more persuasive than the other experts from that proceeding. For instance, to be clear and persuasive, CMP should have addressed the ARP 2000 evidence that CMP experienced very high costs before ARP 2000.[10]

It is likewise difficult to find that CMP has made a clear and persuasive showing that stand-alone CMP would have achieved 1% non-union labor efficiency from 2000 to 2007 because 1% was the productivity factor agreed to in the 1995 ARP stipulation. CMP offers no explanation to show that that one provision in the 1995 stipulation should be viewed as reasonable outside of the context of all the other provisions of the stipulation. CMP does not explain why the productivity factor for a

[10] The Bench Analysis in the ARP 2000 docket stated that in terms of distribution operation and maintenance cost per MWH, CMP ranked 106 highest out of 111 companies and in terms of distribution operation and maintenance per customer, the CMP ranked 101 out of the 111 companies. (ARP 2000 Bench Analysis at 53).

fully integrated electric utility should be applied to a T&D utility. CMP also does not attempt to explain why the financial distress experienced by CMP in 1995, viewed at the time as justification for a lower productivity factor, should be viewed as irrelevant in estimating stand-alone efficiency for 2000 to 2007.

CMP's assumption of 1% as the productivity factor in a stand-alone CMP ARP also is not justified in Mr. Schnitzer's Step 2 analysis. For him to be clear and persuasive, he should have explained why the Commission would have chosen Dr. Malkholm's analysis rather the OPA's or the Bench Analysis. Merely assuming that your witness would have carried the day cannot be viewed as satisfying the criteria set out in the *Merger Order*.

Accordingly, without even reviewing the actual calculations, the Commission should reject the proposed cost-of-service adjustment because CMP has not demonstrated that its proposal will reasonably measure the "but for" merger savings attributable to CMP.

2. Measuring Ratepayer and Shareholder Benefits By Only Examining ARP Productivity Factors Is Unfair and Patently Misleading.

As explained above, CMP did not persuade that it was reasonable in measuring "but for" merger savings nor that it was reasonable in assuming that a stand-alone CMP would have received an ARP with a 1% productivity factor. Thus, it would appear that CMP has overstated both the amount of merger savings and the amount of benefit

that ratepayers received through the operation of ARP 2000 productivity factors. However, Mr. Schnitzer's analysis, which focuses only on ARP productivity factors to measure all the benefits received by ratepayers and *shareholders*, is particularly unfair because, from ratepayers' perspective, the productivity factors were the most advantageous aspect of the ARP 2000 Stipulation. That is the issue on which CMP moved most from its litigation position and in the *Order Approving Stipulation*, the Commission confirmed that the productivity factors were the most attractive feature of the Stipulation for ratepayers. By assuming that ratepayers would fare terribly on that issue in a stand-alone ARP, Mr. Schnitzer can maximize the amount of merger-related benefits that ratepayers receive in ARP 2000..

While his stand-alone assumption of 1% is not justified or reasonable, his failure to focus on any other provision of the ARP 2000 Stipulation results in a fundamental flaw in his analysis: he ignores two factors that are obviously beneficial to shareholders, the opportunity to earn above CMP's cost of capital without risk of a rate investigation or even high-side earnings sharing, and to do so for 7 years not 5 years. These two factors were cited by the Commission, while acknowledging their clear benefit to shareholders, as factors that would make it more difficult for shareholders to recover any portion of any acquisition premium in the future. Yet CMP does not even mention much less measure either benefit.

Regardless of actual financial results, a seven year uninterrupted opportunity to extract synergies and reap all the rewards should be sufficient opportunity to recover a reasonable portion of any acquisition premium. That is why the Commission warned CMP in the *Merger Order* and the *Order Approving Stipulation* that it better accompany any request to recover any merger premium with a clear and persuasive case, and that after 7 years that case would be more difficult. Up to this point, CMP has not met that standard.

In this case, however, the actual financial results demonstrate that ARP 2000 has been quite beneficial to Energy East. An examination of those results weakens CMP's case that explicit or implicit recovery of an acquisition premium in 2008 and beyond, is reasonable or fair.

3. <u>Energy East Has Recovered Substantial "Excess Earnings" During ARP 2000</u>.

As demonstrated in the analysis submitted by Staff consultant Ed Bodmer, attached as Appendix - Merger Premium , CMP has earned over $83 million over its allowed 10.5% cost of equity (COE) return, without adjusting to reduce its equity ratio down to the allowed 47%. Adjusting for the equity ratio down to the allowed 47%, CMP's overearnings are over $96 million (if one makes an adjustment to reflect additional interest expense) or even over $102 million (without an adjustment for interest expense).

These CMP earnings during ARP 2000 were described in the *Order Approving* Stipulation as available to be applied to any merger premium. Indeed, a Moody's analyst stated that Energy East can look at earnings over its allowed ROE "as a defacto recovery of its merger-related goodwill premium and profit from its merger-related cost savings." (Moody's November 2005 report on Energy East Corporation, at p. 5, which is Attachment 1 to the Response to OPA-01-07). CMP cannot be said to have clearly and persuasively demonstrated that its request to recover Energy East's acquisition premium during ARP 2008 should be adopted when it does not even consider its ARP 2000 earnings in assessing the reasonableness of its 2008 request.

4. <u>CMP's Estimation of Its Acquisition Premium Is Not Reasonable.</u>

In Appendix - Merger Premium, Staff consultant Bodmer demonstrates that CMP has not reasonably calculated the amount of merger premium that should be allocated to the T&D business of the CMP Group, Inc. In that analysis, we calculate, conservatively and as a reference point only, a $119 million Market Value acquisition premium that could have been allocated to CMP's T&D utility if we had believed it to be justified. This is conservative because of the conservative valuation we place on CMP's telecommunications subsidiary, NEON when allocating the Market Value premium. Had we chosen to use

a less conservative measure for the valuation of NEON (which was publicly traded between the date of the merger announcement and the merger's closing) we would end up with a reference point Market Value premium allocation to CMP of just under $60 million. When we consider that over the life of the ARP that CMP will have earned almost $96 million over its allowed rate of return, on that basis alone, it appears that Energy East's shareholders did very well regarding recovery of the acquisition premium. When we also consider that additional consolidated tax benefits of $7.5 million annually have accrued to Energy East due to the merger and the fact that Iberdrola S.A. has offered to pay Energy East shareholders a Market Value premium of $1.0 billion in the proposed merger, it appears that there full recovery of the CMP Group premium has already been comfortably achieved.[11]

In summary, CMP has not demonstrated that it is entitled to recover the acquisition premium in an $8.8 million in annual revenue adjustment and we recommend rejection of its recovery proposal. In addition, if we were inclined to allow any recovery, our calculations shown in Appendix - Merger Premium Merger Premium, indicate that Energy East and its shareholders has already realized a sufficient share of merger benefits, and thus recovery of its acquisition premium.

[11] Even if only one-sixth of the $1.0 billion market value Iberdrola has offered for Energy East was allocated to CMP (and we believe it would be higher given the relative sizes of Energy East's subsidiaries), that amounts to $167 million.

IV. AMI

In their summary of CMP's request, Mr. Stinneford and Mr. Dumais state that:

> A central feature of CMP's proposed ARP 2008 is the Company's plan to modernize and upgrade its distribution system by embarking on an advanced metering infrastructure project that will allow the capture and communication of detailed usage information, enable customers to respond to demand response initiatives, and allow CMP to read meters and perform other customer service functions without visiting the customers' premises. The installation of this advanced technology promises to provide significant customer service, demand response, safety and environmental benefits allowing CMP customers to realize the proven benefits of the technological evolution occurring in the electric industry.

ENS/PAD Testimony, at 4-5.

To achieve these goals, CMP proposes to replace its Electronic Meter Reading (EMR) system with an Advanced Metering Infrastructure (AMI) system that includes advanced solid state meters or meter modules for all 630,000 customer accounts. CMP proposes to go out to bid and select a vendor and a specific technology by the end of 2007, begin meter installation in mid-2008, make the AMI system operational by the second quarter of 2009 and complete all meter installation by mid-2010. CMP estimates that the cost of installing its AMI system will be substantial. (See Faust, p.1 for confidential estimate). In a data response, CMP appears to condition its implementation of the AMI system on acceptance of the ARP 2008 rate plan proposed in its filing. (OPA-05-31).

The Advisory Staff supports the laudable goals expressed by CMP in its AMI proposal. Moreover, we applaud CMP's efforts to devote significant resources to prepare itself to be able to bring "smart meter" capability to its customers. As a rate making matter, however, we believe that CMP's AMI proposal is premature and should

not be recognized in either the starting point revenue requirement or the financial modeling used to determine a reasonable ARP.

CMP does not include AMI costs and benefits in the starting point revenue requirement analysis, so there seems to be general agreement that CMP's AMI proposal does not satisfy the known and reasonable criteria needed to be included in such analyses. The costs of implementing the AMI system are as yet unknown and may not be fully known by the end of this proceeding. Furthermore, the Advisory Staff is not yet persuaded that the Commission should adopt CMP's proposal, which may not yield T&D operational savings sufficient to justify the AMI costs. As pointed out by OPA expert witness, Barbara Alexander, CMP does not justify its investment on a utility-only cost-benefit analysis. From the perspective of the T&D utility alone, CMP estimates that AMI costs exceed its benefits. Only by including demand response benefits from the supply market do the total benefits from AMI exceed the costs that ratepayers are asked to bear. However, CMP's cost estimates do not include the hardware or software costs that must be incurred to allow customers' usage to be measured and billed in such a way as to realize these supply market benefits.

Because AMI technology is so new (and changing), as indicated in testimony by the CMP witnesses and Ms. Alexander, there are few utilities in the entire nation that have installed AMI and therefore little actual experience operating such systems. With little AMI investment, demand response programs have not yet developed in a meaningful way in any electricity market in the U.S. Thus, at this time, there is insufficient data or any other evidence to provide sufficient assurance that demand response programs will actually be implemented and achieve sufficient success to

justify the AMI investment. Without successful development of demand response programs, CMP's business case for AMI fails. Indeed, under some scenarios, even with supply market benefits, the CMP's business case results are not robust.

The case for overall benefits to customers is made less clear because of the issue noted above, CMP's current systems cannot support the types of hourly measurement and pricing capability that will be required to achieve supply market benefits. (OPA-05-23, Tr. 21-22, June 20, 2007) The AMI technology cannot be cost effective in CMP's estimation until it implements the billing system changes that enable demand response suppliers to bill and be paid. CMP does not have a cost estimate for the billing system changes. Moreover, it is difficult to estimate such changes since CMP cannot be sure of the type of billing functions demand response suppliers will require because no one yet knows what types of programs will even be offered much less which ones will be successful. Until CMP can reasonably estimate the costs to make the necessary changes to its billing system, it is difficult to conclude that a ratepayer investment into AMI is prudent.

CMP understands that its T&D pricing is not the driver of the billing system changes. Energy or demand response suppliers, who will offer peak pricing and other demand response programs, will drive the billing system upgrades. CMP acknowledges that it will need to have a better understanding of how the peak pricing programs will work in order to change its billing system and it will "have to have some type of outreach to suppliers" in order to determine how its billing system must be updated. (Tr. 23, June 20, 2007). CMP needs to be able to identify the billing system changes, and estimate

the cost of these changes, before the Commission should commit to ratepayer support of the AMI investment.

The Commission should adopt a “go-slow” approach compared to CMP’s proposal because draft legislation is pending in Congress that, if enacted, will provide grants to reimburse some of the costs of investing in “smart grids.” Perhaps with some funding provided by the grants, the business case for AMI looking only at utility costs and benefits could be made.

The technical conference disclosed other details that should be worked out before CMP makes a substantial AMI investment. CMP was not sure whether it would measure loads hourly, or continue to use load profiles. (Tr. 29-30, June 20, 2007). There will be some cost (not estimated) to integrate the new meter data into the load profiling software. (*Id.* at 30). To achieve the energy and capacity savings, on which CMP’s business case depends, it will have to measure on an hourly basis. In addition, CMP had not examined whether costs could be reduced by remote connect/disconnect capability on seasonal accounts. (*Id.* at 36). CMP also has not decided whether to propose an increase to the customer charge, greater than any ARP rate increase that would be permitted, due to the increased meter costs. (*Id.* at 52).

Lastly, it is possible that AMI investment could generate some non-T&D utility revenue, such as from broadband-over-power-lines (BPL) providers or other non-electric utilities for meter reading services. If that occurs, then T&D ratepayers should not be solely responsible for AMI investment. Indeed, perhaps the possibility considered by the legislature in the Electric Restructuring Act might even come about, that metering and billing can be a competitive rather than regulated service.

At this point in time, CMP has not convinced us that ratepayers should, by early 2008, commit financially to a significant AMI investment. Accordingly, in our view, the investment and O&M costs associated with AMI, as well as the capital and expense reductions from implementing AMI, should be removed from the financial modeling used to analyze the reasonableness of any incentive rate plan. In our financial modeling described in section VIII, we make those adjustments.

While we do not believe it proper to consider AMI in the financial analysis used to determine the terms of a reasonable ARP in this case, the Advisory Staff supports further effort and consideration of AMI by CMP. We agree with CMP that the benefits society may achieve are too significant to ignore. Because the Advisory Staff does not wish to allow the pendency of an ARP to discourage CMP from investing in AMI, we would be willing to consider AMI investment as a “carve-out” of the ARP, like mandated costs or expiring amortizations, because CMP may be correct that the business case for AMI cannot be made for the T&D business alone. In such a case, CMP should not be willing to make an investment that will on net, raise its costs. The difficulty in such a “carve-out” is that, while the costs of AMI investment and O&M and the current meter reading cost savings would seem to be relatively simple to measure, many of the other cost savings estimates are more difficult to measure, such as reduced outage restoration costs and costs saved by remote disconnections. In that regard, the AMI “carve-out” may be more controversial and difficult to measure than other “mandated” costs, like a tax change.

V. VEGETATION MANAGEMENT AND RELIABILITY IMPROVEMENT ISSUES

A. <u>WCI’s Recommendation</u>

Based on the findings set out above, WCI made the following recommendations in its Final Report:

- Continue current reliability performance reporting at system level. Individual circuits that exceed 1 standard deviation[12] above the ARP targets should be identified and mitigation efforts stated and followed by CMP as part of an expanded reporting requirement to the MPUC.
- Along with the changes to the vegetation management program, consider tightening ARP targets such that CMP's SAIFI reliability performance improves into the third quartile of national reliability performance within a period of 3 years.
- Consider providing CMP with an incentive for exceeding ARP targets. For example, a provision to permit rewards that would encourage CMP to go beyond managing to the ARP targets and promote continuous reliability improvement programs.
- CMP should review its Distribution Engineer complement and the status of their capability to conduct sufficient long-term planning studies to accommodate both immediate needs and longer-term system needs.
- CMP should maintain a listing of all proposed betterments and provide updates that indicate the disposition of the proposed betterments. For example: completed, budgeted, deferred, no longer needed (with explanation).

[12] Standard deviation is the most common measure of statistical dispersion, measuring how spread out the values in a data set are.

- CMP should enhance its formal 10-year circuit inspection program (that was implemented in 2005) as follows:
    - Extend visual inspection to include pole sounding and visual check from the base of each pole.
    - Include assessment of the status of vegetation encroachment in the inspection report – categorize by contact, danger tree, and within specified clearance ranges. This information should be shared with Vegetation Management to assist in their planning.
    - As the distribution system continues to age, implement specially focused inspection programs that further identify requirements for preventative maintenance actions.
    - Modify the current reactive vegetation management program and provide sufficient budget funding to implement a proactive tree trim cycle of 4 to 5 years. In order to accomplish this, CMP should develop a formal estimate of annual costs to maintain a 4-5 year trim cycle as well as the additional up-front expenditures required to reach a 4-5 year cycle within a reasonable time frame.

B. <u>Overview of CMP's Response to the WCI Report</u>

In response to the recommendations contained in the WCI Report and, as part of its ARP 2008 proposal, CMP proposes to reduce the SAIFI SQI target from its current level of 2.10 to 1.70 by 2014 and to reduce CAIDI from 2.32 to 2.15 by 2014. In order to achieve these targets and to address the concerns raised by the Williams'

Report, the Company proposes to implement a Reliability Improvement Program consisting of the following components:

1. An Enhanced Vegetation Management Plan which includes a 5-year cycle trim program beginning in 2009.

2. An Enhanced Inspection Program which reduces the current inspection cycle from ten years to five-years to coincide with the cycle tree-trimming program.

3. A Pole Replacement Program.

4. An Enhanced Distribution Betterment Program.

The Company has not requested any specific rate adjustments for these programs. The Company has included the revenue requirement impacts of these programs into its ARP 2008 financial modeling and has requested an acceleration of its FAS 106 (Defined Benefit Pension and other Retirement Plans) regulatory liability amortization to offset the increased costs associated with these programs.

The Staff provides a more detailed description of each of the Reliability Improvement Program components, and our position on each component in the sections below.

C. <u>Enhanced Vegetation Management Program</u>

In 2008, CMP plans to spend the current budget for tree trimming ($8.7 million) on its maintenance trimming activities using its current vegetation management program. An additional $2 million would be spent on enhanced activities to address areas of concern identified by its arborists. In 2009, CMP would complete the first year

of the five-year cycle. CMP would also spend an additional $2 million on targeted trimming in 2009. By the end of 2013, CMP would complete the first five-year cycle of trim on all its distribution circuits. At the end of the first five-year cycle CMP would re-set its CAIDI and SAIFI baselines to the WCI recommended levels.

The new 5-year cycle trim program results in a 67% increase in work (60,000 spans per year to 110,000 spans per year). CMP estimates an increase in annual spending by $6.8 million from $8.7 million to $15.5 million for the new 5-year vegetation management activities on the distribution system. Under its new vegetation management proposal CMP estimates a need for an additional four FTE positions – 3 arborists and one full-time administrative assistant, three additional vehicles (Arborist) and 60 additional handheld computer units (120 units in service today) for the additional contractor crews to record the work performed.

The Staff supports the Company's proposal to go to a five-year cycle trim program and believes that the reasonable costs of the program should be recovered in rates. The program should ensure that vegetation issues on all circuits are addressed on a regular basis, and thus should improve reliability and power quality, and should also reduce restoration and line maintenance costs. However, we do have a concern about the proposed date of implementation. The Company has stated that it cannot begin implementation until 2009, citing the need for time to gear up. At this point the Staff is not persuaded that such a long delay is necessary, nor is it desirable. Thus, the Staff recommends an earlier implementation and we have included in our revenue requirement internal costs (labor and capital) associated with the five-year cycle program. If the program is in fact implemented sooner i.e., by the conclusion of this

case, we may revise our revenue requirement proposal to also reflect external contract costs. Otherwise, the Staff recommends that the Company be allowed to defer the incremental costs associated with the five-years cycle trim program for collection in a future case.

Notwithstanding our support for recovery of five-year trim program costs, the Staff believes that the current state of vegetation encroachment on CMP's distribution system, a condition which WCI found to be deficient, can in large part be traced to the level of trimming, or lack thereof, during ARP 2000 and in particular during the early years of ARP 2000. The savings from these costs cut-backs flowed directly to shareholders and, thus, the costs to catch-up and to get the Company on a plane where it can effectively go to a 5-year trim cycle should not be borne by the Company's ratepayers.

The following table extracted from the WCI Report compare amounts CMP collected in rates during ARP 2000 (based on amounts included in the Company's last rate case, (Docket No. 97-580) and CMP's spending during the same period:

VEGETATION SPENDING DURING ARP 2000

Year	Collected	Spent	Difference
2001	9,287	8,936	(351)
2002	9,275	7,692	(1,583)
2003	9,258	8,864	(394)
2004	9,153	8,103	(1,050)
2005	9,122	8,554	(568)
2006	9,173	9,058	(115)
Totals	55,268	51,207	(4,061)

During the 2001-2005 time-period CMP trimmed the following parts of its system:

Trim Statistics

	2001	2002	2003	2004	2005
System Treed Circuit Miles	18,558	17,773	18,044	16,638	17,466
OH Spans Cleared	50,608	42,515	60,021	59,754	59,746
OH Calc Miles Trim	1,947	1,635	2,309	2,298	2,298
Equiv Cycle (years)	9.0	10.9	7.8	7.2	7.6

> Based on this information WCI found:
>
> CMP has been able to reduce the equivalent trim cycle from 9-10 years to about 7 years, but with an average vegetation growth rate of 1.5 feet per year and an average 8 foot side clearance, vegetation would grow back into the primary conductor in about 5 years. So with an effective 7 plus year trim cycle, vegetation encroachment continues to be a problem. As discussed in industry trade articles tree liability increases in a geometric fashion if vegetation management programs are under funded, leading to increased tree-related outages and significantly higher costs to catch up.

In its Report, WCI estimated that between 12.7% and 19% of the Company's circuits have vegetation currently in contact with its distribution lines and that another 15.8% to 23.8% are within 3 feet of the lines. WCI recommended that CMP should undertake to remediate clearances immediately where vegetation is in direct contact with conductor and within one year where it is within 3 feet of the conductor. WCI went on to state that:

> Without a complete vegetation survey or extensive analytical study, we cannot accurately estimate the level or period of catch-up costs. We suggest that CMP prioritize its first year of catch-up activities to mitigate all of the tree limbs that are in contact with primary conductor and a sizeable portion of those that are within 3 feet of the conductor. Assuming an average vegetation growth rate of 1.5 feet per year, a portion of the balance of the limb initially within 3 feet will, by the second year, be in contact with the primary conductor and should be mitigated on a priority basis. Again, given the average growth rate, there may always be limbs that grow into contact with the primary conductor, even with a 5-years trim cycle, and these should receive priority during the then current year.

> While we cannot accurately determine the costs of the catch-up effort, we have estimated that the catch-up will cost in the range of $4 million to $5 million, based on the condition assessment results for trees in contact or within 3 feet.

The Company has allocated an additional $2 million for tree-trimming in 2008 and 2009 in addition to its normal tree-trimming budget of $8.7 million in 2008 and its cycle tree trim budget of $15 million in 2009 to address the need for a "catch-up" as identified by WCI. Under the Company's "catch-up" program, the Company has directed its arborists to identify those problem circuits which should be trimmed within the context of this $2 million budget. While the overall amounts allotted by the Company for the catch-up program are close to the amounts estimated to be required by WCI, it does not appear that the Company has endeavored to do the comprehensive review envisioned by WCI to perform the catch-up to the cycle trim program. Of particular concern to the Staff is the circuits that will be trimmed at the back end of the cycle. Under the Company's proposal, the last segment of the cycle trim program will be done in 2013. If those circuits currently had spans with vegetation in contact, by the time the Company got to the circuit for trimming, and assuming a 1.5 foot growth rate, the vegetation would be 9 feet over the lines.

The Staff therefore requests that the Company include at least the design of its catch-up program in its rebuttal case in this proceeding, the costs associated with the program, and an explanation as to why the Company believes such costs should be recovered from ratepayers.

C. <u>Enhanced Inspection Program</u>

During the initial grid review conducted by the Commission in 2004, CMP stated that it no longer had a formal inspection program and was now relying on employees, such as meter readers, to conduct safety and condition inspections as part of their overall job duties. In response to concerns raised by the Commission Staff, the Company agreed to reinstate a formal inspection program using a 10-year inspection cycle. As part of its Reliability Improvement Program, the Company in this case has proposed an Enhanced Inspection Program which would shorten the inspection cycle from 10 years to 5 years. The primary rationale for going to a 5-year cycle appears to be that by doing so, CMP will be able to synchronize the inspections with the tree-trimming program, also on a five-year cycle, so that the inspections will be done on the circuits in the year following the year that they are trimmed, thereby allowing a clear view of the lines and equipment.

The Staff agrees with the Company that going to a 5-year cycle which is coordinated with the tree-trimming program should yield safety and reliability benefits. Given the rationale for the program, the Staff recommends that the program not be implemented until the year following the implementation of the cycle tree-trimming program and that the costs of the program be included in rates in a subsequent rate case following implementation. If an ARP is approved as part of this proceeding, the Staff would recommend that the Company be allowed recovery for reasonably-incurred costs of the program (based on the forecasted costs presented by the Company in this case), as a flow-through item in the year following implementation of the program which as we note above should occur in the year following implementation of the 5-year cycle trim program..

D. Pole Replacement Program

Under the Pole Replacement Program component of its ARP, CMP proposes to replace all poles installed prior to 1937 at a rate of 440 per year. CMP estimates the costs of the program to be $800,000 per year and the O&M costs to be $155,000. CMP was not able to provide any difinitive rationale for choosing 1937 as the dividing line for replacing existing poles.

As part of its Final Report, WCI found that CMP's pole plant was in relatively good shape but recommended that as part of its inspection process the Company extend its current inspection program to include pole sounding and that CMP should consider pole strength testing and pole integrity testing, particularly on poles older than system average. The Company has agreed to incorporate pole sounding as part of its inspection program.

In the past, the Company has argued that it is the condition of poles rather than age that is important. The Staff agrees with this approach and believes that poles requiring replacement can best be identified as part of the Company's Enhanced Inspection Program. With regular inspection and sounding, poles in need of replacement should be identified and we assume once identified they would be replaced. Thus, the Pole Replacement Program seems duplicative of the inspection process. Therefore, we do not believe the Pole Replacement Program is a necessary component of the RIP and recommend against including costs associated with the proposed Pole Replacement Program in rates in this case.

E. Distribution Betterment Program

CMP currently averages approximately $5 million in spending for betterment projects each year. Under the Enhanced Betterment Plan proposed by CMP, the Company would increase betterment spending for additional projects by $3 million in 2008, $4 million in 2009 and $6 million in years 2010 through 2014. CMP would also incorporate WCI's recommendation to improve its record keeping for betterments by keeping records for current year proposed projects up to seven years.

In order to implement this enhanced plan CMP has indicated a need for the following additional resources.

- Two Distribution Engineers;
- Five Field Planners;
- Eighteen Line Workers (First Class);
- Three Line Supervisors;
- Three Safety Specialists;
- One Field Analyst;
- Two Real Estate Analysts;
- One and one-half full-time equivalent Environmental Analysts;
- Nine Bucket Trucks – For Line Workers;
- Three Pick-up Trucks – For Line Supervisors; and
- Three Pick-up Trucks – For Safety Specialists,

CMP supplied a list of additional betterments that its engineers and service center personnel submitted to support the increase in need for spending. CMP has acknowledged that the projects on the current list, especially in the out years will bear little relation to what actually winds up being done for betterments. CMP maintains

that what will not change, however, is the amount that the Company spends on betterments which will be based on the amounts proposed as part of CMP's ARP proposal.

In its Report to the Commission, WCI found that CMP's overhead distribution plant appeared to be in good condition. Therefore, Staff is unsure of the rationale for the Enhanced Betterment program. CMP has stated that it will assist the Company in achieving its proposed tougher service quality targets. After reviewing the list of additional betterments provided in Mr. Watson's testimony (MLW-6), Staff has concerns with the process and methodology used for justifying the current need for this amount of investment. Even though there are many projects on the list that appear to be needed based on conditions that affect the reliability of the system there are also many that appear to not have any relationship at all with the system's performance. Without a detailed type of analysis it is impossible for Staff to determine that a doubling in the betterment budget is warranted, or if warranted, was the result of delaying needed projects in previous years.

Given WCI's finding on general plant condition, the lack of persuasive rationale for the program, the indefiniteness of the program in terms of scope and actual implementation, the Staff believes that the costs of this component of the RIP should not be incorporated into the revenue requirement calculations in this case. Instead, the Staff believes that the Commission should follow the principle of "rates following service" and costs associated with prudent betterment investments be included in rates after such investments are made.

VI. RETURN ON EQUITY AND COST OF CAPITAL

A. Cost of Capital

1. Summary

We have considered the direct testimonies of CMP witness Robert Rosenberg, OPA witness Stephen Hill and done our own analysis of financial market conditions and recommend the adoption of a 9.80% return on equity (ROE) for CMP's distribution operations. Our recommended capital structure for CMP is 45.0% common equity, 2.0% preferred equity, 48.0% long-term debt and 5.0% short-term debt. Using these weightings and embedded cost rates provided by CMP for debt and preferred equity, our recommended ROE produces a pre-tax weighted average cost of capital (WACC) of 10.90% and after-tax weighted average cost of capital of 7.79% as shown in Table 1 below.

Table 1

	Amount (%)	Cost (%)	After-Tax Weighted	Pre-Tax Weighted*
Common Equity	45.00%	9.80%	4.41%	7.45%
Preferred Equity	2.00%	4.99%	0.10%	0.17%
Long-term Debt	48.00%	6.28%	3.01%	3.01%
Short-term Debt	5.00%	5.40%	0.27%	0.27%
Total	100.00%		7.79%	10.90%

* Tax Rate is 40.8%.

The 9.80% ROE reflects Staff's opinion that the T&D-only segment of electric utility operations has a very low business risk profile, a view that is shared in the investment community and one that is promoted by Energy East itself in its presentations in various investment forums. Also, despite recent increases in short-

term interest rates, long-term capital costs, as measured by interest rates on treasury and utility bonds, continue to be quite low by historical standards, as pointed out by the OPA's Mr. Hill in his testimony. Our recommendation relies on the results generated by the quarterly and annual versions of the familiar Discounted Cash Flow (DCF) model applied to two peer groups of comparable utilities. We note that three different variations of the DCF model were used in this case and the final results were fairly consistent. Mr. Rosenberg found a DCF range of 9.0% to 10.0%, while Mr. Hill's DCF analysis yielded an estimate of 9.28%. Our own analyses indicated a 9.80% ROE for the Electric peer group and a 9.20% ROE for the natural gas local distribution company peer group (the "LDC" peers).

The "Electric" utility peer group, was originally derived by CMP witness Robert Rosenberg and affirmed by OPA witness Stephen Hill, and was comprised of electric and combination gas & electric utilities. We made a slight adjustment to the Electric peer group also constructed a second peer group of natural gas LDCs primarily as a check on the reasonableness of the results generated using the Electric peer group. We have also applied the Capital Asset Pricing Model (CAPM) to both peer groups as a check methodology, but have less confidence in those results than usual for reasons we will describe further below.

As we have done in the past, we also calculated the appropriate magnitude of common equity flotation costs and have incorporated a small upward adjustment of approximately 10 basis points (0.10%) into our 9.80% ROE recommendation. For a number of reasons that we will explain further below, we

question whether this customary adjustment continues to be warranted for utilities like CMP and will consider abandoning this adjustment going forward.

In dollar terms, the WACC recommendations of the OPA and CMP differ by approximately $13.1 million in annual revenue requirement. Advisory Staff's recommended WACC would result in an annual revenue requirement that is approximately $10.4 million lower than CMP's recommendation.

2. Advisory Staff Analysis

a. Peer Groups

CMP witness Rosenberg identified a peer group of nine electric and combination gas & electric utilities in his direct testimony using several screening criteria. Starting with the *Value Line Investment Survey* universe of electric utilities, Mr. Rosenberg required peer group companies to have corporate bond ratings of Baa1 or higher from Moody's and BBB+ or higher from Standard & Poor's. Companies also could not be involved in merger activity, had to be paying common dividends and could not have "significant" unregulated operations. OPA witness Hill agreed with Mr. Rosenberg's screening process and used the same peer group as the basis for his analysis.

Advisory Staff used this peer group as well but added an additional screening filter. In order to be included, each company had to have available a published consensus 5-year analysts earnings growth rate forecast from a source such as FirstCall/Reuters, Yahoo Finance! or Zack's Investment Service. This resulted in dropping two utilities and resulted in a seven company "Electric" peer group. The surviving companies were Alliant Energy Corporation, Consolidated Edison, NSTAR,

SCANA Corporation, Southern Company, Vectren Corporation, and Wisconsin Energy Corporation. This group had a median common equity ratio of 44.5%.

In addition to an "Electric" utility peer group, Advisory Staff also constructed a natural gas distribution utility or "LDC" peer group for use in its analysis. LDC's that do not have significant unregulated operations are, like CMP as a T&D-only electric utility, primarily "pipes and wires" utilities. That is, they have the responsibility for safely delivering natural gas over their system, but generally do not have responsibility for producing natural gas. LDC's instead procure natural gas and sell it to their customers at cost which is analogous to the manner in which Maine's three major electric utilities currently operate in procuring generation service. The screening criteria for narrowing the LDC field were similar to the ones used in creating the Electric peer group. The starting universe was the *AUS Utility Reports* group of 28 natural gas LDCs. Companies were required to be currently paying common dividends, to not be involved in merger activity, to have a published consensus analyst's 5-year earnings growth rate forecast available and had to have a majority (greater than 50% per *AUS*) of revenues from regulated natural gas operations. The bond rating criterion was that each company had to have a bond rating between BBB-/Baa3 at the low end and A/A1 (S&P/Moody's) at the high end.

The result was a seven company LDC peer group that includes AGL Resources, Atmos Energy Corporation, LaClede Group, National Fuel Gas Company, Piedmont Natural Gas Company, South Jersey Industries and Southwest Gas Corporation. This peer group had a median common equity ratio of 48.7%. We believe that these peer groups are appropriate for evaluating CMPs ROE

and likely bracket the total risk profile of CMP with the Electric peer group being a little more risky than CMP and the LDC peer group being a little less risky than CMP.[13] Other than NSTAR, the companies populating the Electric peer group all own generation assets and thus are less "pipes & wires" utilities than CMP is currently. On the other hand, the companies populating the LDC peer group are very much "pipes & wires" utilities even those owning interstate transmission pipelines. Offsetting some of low risk "pipes & wires" profile for the LDCs is that they intuitively appear to be more at risk from competition, especially at the residential level, from sources such as heating oil dealers in some areas of the country and from electric utilities in some areas of the country.

In his testimony on page 7, CMP's witness Mr. Rosenberg states that CMP's bond rating S&P and Moody's bond ratings of BBB+ and A3 respectively are lower than the median bond rating of the peer group he constructed as a reason why he believes that his Electric peer group is less risky than CMP and later uses this assertion as one reason to make a final recommendation that is well above what his DCF analysis shows to be a reasonable ROE. We do not share his view for a number of reasons. First, based upon our reading of the credit reports filed by CMP in response to OPA Data Request 1-07, we believe that CMP's bond rating may be artificially constrained by that of Energy East and could be higher on a stand-alone

[13] A company's "Total Risk" profile is the combination of its "Financial Risk" profile (i.e. how much debt the company issues) and its "Business Risk" profile (i.e. how predictable cash flows are from normal business operations).

basis.[14] In its August 26, 2006 report on CMP, Fitch cited as its ***Key Credit Concern*** "*Exposure to a lower rated parent*." (CMP Response to ODR 01-32). In its September 6, 2006 report on CMP Moody's stated on page 2 that: "*CMP has a very low business risk profile since it sold its generation assets thus transforming itself into a pure regulated electric transmission and distribution utility" and that Energy East "…has $1.3 billion of standalone debt, which has a tempering effect on CMP's rating*."

As an illustration of how one segment of the financial market views the business risk environment for a T&D-only utility in Maine, we note that Bangor Hydro-Electric Company (BHE) is in the process of issuing $50 million in *unsecured* long-term debt. BHE's advisor, Banc of America Securities LLC., expects that it will be able to place the issuance this month at a credit spread of 120 basis points (1.20%) over the comparable maturity Treasury Bond, in this case the 10-Year T-Bond. According to Reuters, this is the credit spread that a utility with a rating in the low to mid "Double A" range could expect to receive.[15] Considering that this debt is unsecured, that BHE's service territory is most likely not as healthy economically on average as CMP's service territory, and that BHE and CMP operate under the same regulatory regime, it seems likely that a standalone CMP would be less risky than BHE. [16]

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[14] Currently, Moody's rates CMP as two "notches" higher than Energy East at A3 versus Baa2, S&P rates both companies the same at BBB+, while Fitch rates CMP one "notch" higher than its parent at BBB+ versus Energy East's BBB.

[15] Low to mid "Double A" means AA- to AA for S&P (or Fitch) and Aa3 to Aa2 for Moody's. Reuters Corporate Spread data is attached as Bench Exhibit ROR-1.

[16] For example, the Maine State Housing Authority recently published median household income figures showing CMP-served counties of Androscoggin, Cumberland and York at $42k, $53k and $51k respectively compared to BHE-served counties of Hancock, Penobscot and Washington at $43k, $40k and $30k respectively.

Also of interest in this regard is Energy East's portrayal of its own business risks to the investment community. In a January 2007 "Management Presentation" (page 12) found on Energy East's web site, the company states that it is a "pipes & wires company," has "minimal non-regulated businesses," has "no trading operations," has "protection from uncontrollable costs" and has a "clean and solid balance sheet." Subsequent presentations to the investment community in April and May of 2007 cite "predictable earnings and cash flow" as factors for potential investors to consider when contemplating the prospects for Energy East. All of these factors suggest that Energy East is a relatively low-risk enterprise, and all of these factors happen to also describe CMP's "T&D-only" electric utility operations as well.

B. Estimation Models & Results

1. DCF Model

Advisory Staff has historically preferred the Quarterly DCF (QDCF) to the traditional "Annual" version of the DCF (ADCF), but has provided both calculations in the past and has similarly provided them here in Bench Exhibits ROR-2 and ROR-3. These calculations are largely self-explanatory. To summarize, in order to calculate the ADCF results, the current annualized dividend for each utility as of September 4, 2007 was converted it to a "forward" dividend by multiplying it by (1+g%) where "g%" is the average of three "consensus" 5-year earnings growth forecasts published by the Zacks, Yahoo! Finance and Reuters.[17] The resulting forward dividend was then divided by the 20-Day average closing share price in order to calculate the forward dividend yield portion of the DCF calculation. The same consensus growth rate

[17] We collected this information on September 4 and 5, 2007.

was then added to the resulting forward dividend yield to arrive at the final ROE estimate.

To calculate the Quarterly DCF results, we took the current quarterly dividend for each utility as of September 4, 2007 and converted it to a "forward" quarterly dividend by multiplying it by (1+g%) where "g%" is the same growth rate described above. The resulting forward quarterly dividend was, again, divided by the 20-Day average closing share price in order to calculate the forward quarterly dividend yield. This yield figure was then raised to the fourth power to annualize the forward quarterly yield before it was added to the consensus growth rate to reach the final ROE estimate. After calculating ROE using both models, we made two additional adjustments to reach our current recommendation. First, we made an allowance for the recovery of common equity "flotation costs" which we describe further below and then we trimmed what we considered to be unreasonably low or unreasonably high DCF estimates.

Excluding individual DCF estimates that we consider to be anomalous is largely judgmental. On the low side, with current BBB/Baa2 rated utility bond yields in the 6.40% range, we felt that the AGL Resources estimate result of 6.02% in the LDC peer group was clearly flawed and removed it. On the high side, we removed Wisconsin Energy Group's 11.71% QDCF estimate (11.68% in the ADCF) because it appeared to be a clear outlier at 90 basis points higher than the next closest estimate and approximately two standard deviations higher than the average for the group.

For the Electric utility peer group, our resulting ADCF range was 8.95% to 10.55% (9.74% midpoint) and our QDCF range was 9.04% to 10.62% (9.83% midpoint). For the LDC peer group, our ADCF ROE range was 7.76% to 10.44% (9.10% midpoint) and the QDCF range was 7.79% to 10.54% (9.17% midpoint). We would note that the difference between the ADCF and QDCF estimates are relatively small.

2. Capital Asset Pricing Model (CAPM)

The theory and formulation of the CAPM was described in detail in the testimonies of both Mr. Rosenberg and Mr. Hill and we will not reproduce that discussion here. The parameters that are needed to estimate ROE using the CAPM model are the Risk-Free investment rate (R_f), a stock beta (β), which is the measure of risk in the formula, and the Equity Market Risk Premium (R_m- R_f). The Risk Free rate is not usually controversial and in this case both parties and the Advisors are in general agreement that the 30-year Treasury Bond is an appropriate proxy for that parameter. On September 10, 2007, the Federal Reserve's H.15 publication reported the 30-year Treasury Bond rate to be 4.78% (for our calculations below, we rounded this to 4.80%).

Regarding the other two parameters in the model there is generally no easy way to find consensus forward-looking estimates of either beta or the equity market risk premium. This is a primary weakness in the CAPM and is a primary reason why the Commission as traditionally relegated this estimation technique to the role of a check methodology. For beta, analysts generally rely on *Value Line's* published betas, but these betas are calculated over the most recent 5 years of history and are not truly forward-looking. Estimating the last parameter, the forward-looking equity market risk

premium, is often the most difficult exercise in constructing a CAPM analysis. Some analysts rely on historical relationships between equities and Treasury securities while others attempt to estimate forward-looking premiums using market data. That is the case in this docket as OPA witness Hill's CAPM analysis uses historical equity market risk premiums of 5.00% and 6.50%, but he also presents evidence that the true current forward-looking equity market risk premium is likely to be much lower than historical averages. Mr. Rosenberg disagrees and his CAPM analysis uses a historical premium of 7.10% and his own estimated forward-looking market risk premium of 8.70%.

CMP's testimony includes an internal inconsistency regarding the forward-looking equity market risk premium which Mr. Hill touches on in his testimony. Hill Pref. Dir. at 5. The forward-looking expected return on CMPs pension fund portfolio, which is comprised of bonds, equities and other investments, is 8.75%. In the Company's confidential response to ODR 01-33, CMP shows both the asset allocation for its pension fund as well as the expected returns for each asset class, including "Large" equities, "Small" equities and "International" equities. The expected returns used by CMP for these asset classes do not coincide with an equity market risk premium nearly as high as either of the premium levels recommended by Mr. Rosenberg (or for that matter as high as those provided by the OPA's Mr. Hill). This tends to support the contention of Mr. Hill that equity market risk premiums are not as high as historical measures would suggest.

Both witnesses collected *Value Line* beta estimates for the Electric utility peer group which we have verified. We also collected beta estimates for the LDC peer group and betas for both peer groups are shown on Bench Exhibit ROR-4. The

range of beta estimates for both the Electric utility peer group and for the LDC peer group is 0.70 to 0.95 with a median of 0.80 for the Electric utility peer group and 0.85 for the LDC peer group. As noted previously, we believe that the Electric utility peer group has a somewhat higher risk profile than does CMP and we are therefore skeptical of the usefulness of the beta estimates indicated by Mr. Rosenberg's peer groups.

As a test of reasonableness, we examined the betas of two small eastern electric utilities from the *Value Line's Expanded Edition* and found the betas of Maine Public Service Company's (MPS) publicly traded parent, Maine & Maritimes Corporation to be 0.35 and that of Unitil Corporation of New Hampshire to be 0.45.[18] We also noted that Central Vermont Public Service Company, a small electric utility serving a relatively rural state had a beta of 0.70 while it continues to own generation assets, which theoretically should make that company somewhat riskier than CMP. Because these companies did not have published consensus 5-years earnings growth rate forecasts, they were not included in the Electric utility peer groups and we could not apply our DCF models to them. If we chose to, we could have used the Maine & Maritimes beta (essentially MPS's beta) in the CAPM because that company is a T&D-only electric utility operating in Maine under the same rules as CMP. As was the case with BHE, we believe it is safe to assume that the service territory of MPS is not as healthy economically as the service territory of CMP, so it is likely that CMP is less risky than MPS. Rather than using Maine & Maritimes beta directly in the CAPM, we chose to be conservative and simply used the betas of Maine & Maritimes, Unitil Corporation

[18] Maine & Maritimes does not own generation assets and Unitil has also divested the bulk of its generation assets and currently owns less than a 1% interest in Wyman Unit 4 in Yarmouth, Maine.

and Central Vermont Public Service Company to conclude that it is likely that CMP's true beta is at the bottom of the Electric and LDC peer group ranges, at 0.70, rather than near the middle of the range. The appropriate *Value Line* pages for Maine & Maritimes, Unitil Corporation and Central Vermont Public Service are attached as Exhibit ROR –5.

As Table 2 below illustrates, at a beta of 0.70, a Risk Free rate of 4.80%, and assuming the forward-looking equity market risk premium is within the range of Mr. Hill's high-end historical estimate of 6.50% and Mr. Rosenberg's historical estimate of 7.10%, the CAPM suggests an ROE between 9.33% and 9.75% before flotation costs is appropriate for CMP. Adding 10 basis points for flotation costs would raise the CAPM range to 9.43% to 9.85% with an indicated midpoint of approximately 9.65%. This is consistent with our current recommendation of 9.80%.

Table 2

Examiners CAPM Results

Beta (β)	**R_f**	**R_m-R_f 6.50%**	**R_m-R_f 6.80%**	**R_m-R_f 7.10%**
0.70	4.80%	9.33%	9.54%	9.75%

CAPM Formula = $R_f + \beta \times (R_m - R_f)$

C. Common Equity Ratio

We have consistently used market data over the years to evaluate the appropriateness of proposed common equity ratios based on the premise that the capital structures of publicly traded companies were the best indicator of a cost-efficient mix of debt and equity for companies of a given business risk profile. Our Bench Exhibit ROR-6, shows the common equity ratio results we found from sorting the data in the August 2007 issue of *AUS Utility Reports* by bond rating. The 64-company sample of "Electric Utilities" and "Combination Electric & Gas Utilities" showed an average common equity ratio of 44.5% with a median of 44.4%.[19] Utilities in CMP's ratings range, the Low Single-A to High Triple-B range (that is A-/BBB+ for S&P and A3/Baa1 for Moody's) also showed median common equity ratios in the 43.5% to 44.5% range . It should be noted that CMP's parent, Energy East Corporation, had a common equity ratio of 44.3%, which had increased recently from approximately 41.0% following its March 2007 issuance of $218 million in new common equity. CMP's current bond ratings are BBB+ from S&P (and also from Fitch Ratings) and A3 from Moody's and S&P assigns CMP an above average "3" business risk profile (scale is 1 to 10 with "1" being the least risky). Moody's commentary, as noted previously, similarly characterizes CMP's business risk profile as being "very low." Given this, our view is that CMP as a T&D-only electric utility could safely support a common equity ratio equal to that of level of the industry median if not lower.

OPA's witness Mr. Hill has also analyzed the appropriate common equity ratio for CMP in detail in his Testimony on pages 21 - 26 and demonstrated a sound

[19] AUS properly includes short-term debt and current maturities of long-term debt in its determination of common equity ratios.

basis for his recommended 45.0% common equity ratio. Although we believe that 45.0% represents the top of what we believe is necessary for CMP, this does not differ greatly from the data we examined and we would support using a 45.0% common equity ratio in this case. In order to implement a 45% common equity ratio, Mr. Hill simply assigns the reduction in common equity in its entirety to long-term debt. As shown on Bench Exhibit ROR-7 we allocated the reduction in common equity on a pro-rata basis to long-term and short-term debt respectively at approximately a 90%/10% split.

D. Flotation Costs

Since at least the early 1990's the Commission has allowed a common equity flotation cost adjustment in its ROE findings. We believe that a flotation cost adjustment may be appropriate and calculated what we believe to be reasonable if we ultimately decide to recommend one in this case. Our data indicates that flotation costs are in the range of 2.0% of total dollars issued as shown on Bench Exhibit ROR-8. When this adjustment is run through our DCF calculations, the impact is on the order of an 8 to 10 basis point (0.08% to 0.10%) upward adjustment in total ROE.

Bench Exhibit ROR-8 is the electric industry survey used by the Commission in its final Order in *Investigation of Stranded Cost Recovery, Transmission and Distribution Utility Revenue Requirements and Rate Design of Bangor Hydro-Electric Company*, Docket No. 97-596, (November 24, 1999). In addition to the survey data collected in that docket, this Exhibit shows both the reported issuance costs for the recent common equity offering by CMP's parent, Energy East Corporation, plus Energy East's own experience issuing common equity via its Dividend Reinvestment Program

(DRP) during the years following the acquisition of CMP in September of 2000. We note that Energy East's most recent issuance costs are not significantly different than those that were common in the industry during the 1994 to 1996 survey period.

As noted, there are reasons for us to revisit the Commission's long-standing precedent regarding flotation costs. First, it appears that companies (including Energy East, BHE's parent ,Emera, Inc., and Verizon) are relying more heavily on DRP programs as a source of new equity. Since CMP was acquired by Energy East just over 6 years ago, Energy East has raised common equity through its DRP program at a relatively steady pace. During that period it appears that approximately $109 million in common equity was raised in this manner, representing roughly half of its most recently issued total ($218 million). It appears, however, that Energy East's most recent issuance is the first one made by the company (or its predecessor NYSEG) in a very long time. Our survey indicates that NYSEG did not make a public offering in the 1994 to 1996 timeframe and we are not aware of another public offering by the company prior to its March 2007 offering.[20] Given the infrequency of public issuances as well as the existence of a DRP program that raises equity on a regular basis at an incremental cost that should be negligible, a fresh look at this topic is warranted.

Another consideration regarding a flotation cost adjustment on common equity concerns the materiality of the adjustment. From practical standpoint an upward flotation cost adjustment of 8 to 10 basis points on ROE has become small enough that it could almost be considered "rounding error" in reaching a final determination of ROE.

[20] If the Company has made another public offering in the past 10 years, it should provide copies of any offering prospectuses in its Rebuttal filing.

With DRP's making total issuance costs as a percentage of the amount issued smaller, and large holding companies raising capital for all subsidiaries at once (a benefit often touted by acquirers for the utilities they wish to acquire) the process should be becoming much more cost efficient than it was in the past. With the pending application for approval of Iberdrola's acquisition of Energy East (and thus CMP), CMP's share of the cost of raising common equity should be reduced even further.

Finally, beginning on page 37 of his direct testimony, Mr. Hill lays out a number of reasons flotation costs are inappropriate for recovery as a specific adjustment to ROE. We find Mr. Hill's argument that a utility that issues common shares at prices in excess of book value has in effect recovered its flotation costs (underwriting plus out-of-pocket costs) many times over to be somewhat persuasive. If Mr. Rosenberg has any further evidence regarding the appropriateness of equity flotation cost recovery, given CMP's current circumstances, he should include it in his rebuttal testimony.

E. Mr. Rosenberg's Testimony

CMP's witness Robert Rosenberg recommended a Return on Equity (ROE) of 11.0% on CMP's distribution operations which translates to a pre-tax Weighted Average Cost of Capital (WACC) of 12.70% on distribution rate base. Mr. Rosenberg arrived at his ROE recommendation by applying several different models to his electric utility peer group, including the "Two-stage" version of the DCF and two versions of the CAPM (CAPM and ECAPM). He also employed two variations of historical risk premium model (the "HRP models") which were not linked to his electric utility peer group. Finally, Mr. Rosenberg conducted a "Comparable Earnings" study on

a sample group of industrial companies (non-utilities) which he believed to be comparable in risk to CMP. In order to arrive at a WACC of 12.70%, Mr. Rosenberg used what appears to be CMPs most recent actual capital structure which was made up of 52.2% common equity, 1.6% preferred equity, 41.6% long-term debt and 4.6% short-term debt. Mr. Rosenberg did not provide any support for his recommended 52.2% common equity ratio for CMP. Although Mr. Rosenberg did not make an explicit recommendation on flotation costs, he suggested that an adjustment on the order of 15 basis points (0.15%) was included in his final recommendation.

1. General Methodological Observations

For at least the last 15 to 20 years the Commission has expressed a preference for single-stage DCF models used on peer groups of utilities as its primary determinant of a utility's ROE. The CAPM has principally been used as a check methodology, while Two-stage formulations of the DCF, the "Empirical" CAPM (or ECAPM), HRP and Comparable Earnings models have typically been dismissed altogether, most recently in *Investigation of Central Maine Power Company's Stranded Costs, Transmission and Distribution Utility Revenue Requirements and Rate Design*, Docket No. 97-580 (Order at 49-55). Although Mr. Rosenberg's Two-stage DCF model produces ROE estimates that are similar to those produced by the Single-stage models introduced by the OPA and Advisory Staff in this case, we are not persuaded that CMP or the T&D electric utility industry as a whole will experience a sudden shift in long-term dividend growth rates in five years, the effect of which can only be captured by employing a Two-stage DCF model. In addition, Mr. Rosenberg's choices for "second stage" dividend growth rates are not supported for a number of reasons which the

OPA's witness Mr. Hill describes in detail on pages 50 – 53 of his Testimony. To date we have not been presented with evidence that will enable us to recommend that the Commission adopt any of Mr. Rosenberg's models outright. We are also unable at this time to recommend that any of the alternate models proposed by Mr. Rosenberg should be accorded equal weighting with the traditional Single-stage versions of the DCF model in determining a utility's ROE.

F. Mr. Hill's Testimony

The OPA's Mr. Hill's relied primarily on the traditional single-stage ADCF to reach his recommendation of a 9.25% ROE for CMP. He also used a number of check methodologies including a CAPM analysis, Modified Earnings-Price Ratio or "MEPR" model and a Market-to-Book or "MTB" Model. Mr. Hill strongly recommended against allowing any common equity flotation cost adjustment, and also against the Company's proposed common equity ratio of 52.2%. Mr. Hill did a rather extensive analysis on the issue of the appropriate common equity ratio and recommended a capital structure for CMP containing a common equity component of 45.0%, a preferred equity component of 1.56%, a long-term debt component of 48.84%, and a short-term debt component of 4.60%. Hill Exhibit SGH-1, Schedule 2, page 4 of 4. Mr. Hill's recommendation of a 9.25% ROE combined with his recommended capital structure results in a pre-tax WACC of 10.48% for CMP.

1. General Methodological Observations

We believe that Mr. Hill's general approach for estimating CMP's ROE is sound however we disagree with some of the specific inputs in his DCF and CAPM models and we note that in the past the Commission has not placed any weight

on his MEPR or MTB models. To this point, we have not been presented any evidence that would cause us to recommend that the Commission place any weight on Mr. Hill's MEPR and MTB models. Based in part on evidence provided by Mr. Hill, we are however revisiting the issue of allowing a common equity flotation cost adjustment in CMP's ROE.

With regard to Mr. Hill's DCF analysis, we have observed in the past that Mr. Hill does not consistently use the "next-period" indicated dividend in calculating the forward-looking yield in his DCF calculations. In this case, he has failed to do so and this introduces a downward bias in his DCF results. We believe that the impact of making this adjustment would raise Mr. Hill's DCF results by something on the order of 10 basis points.

In addition, the Commission (and Advisory Staff) and Mr. Hill have disagreed over the years over the long-term dividend growth rate that should be used in the DCF model and also about the use of quarterly compounding of dividends in the DCF model. Regarding the dividend growth rate, Mr. Hill prefers the internal growth rate formula of BR+SV while Advisory Staff and the Commission have expressed a preference for the consensus 5-year earnings growth forecasts published by Wall Street analysts. We do not believe that on a case by case basis that this philosophical difference introduces a systematic bias in either direction in Mr. Hill's analyses.

Regarding the recognition of quarterly timing of dividend payments, the Advisory Staff's and the Commission's historical preference for the QDCF over the ADCF often results in a differential of 15 to 20 basis points. We noted previously,

however, that at this time the differential is 10 basis points or less, so our disagreement with Mr. Hill on this specific issue is not overly significant by itself.

Turning to the CAPM, we continue to disagree with Mr. Hill's use of the geometric mean historical equity market risk premium versus the arithmetic mean historical equity market risk premium and believe, that to the extent one should rely on a historical risk premiums at all in CAPM analyses, that the arithmetic mean is more appropriate. If we are correct, and ultimately find that the geometric mean is should not be used in CAPM analyses, then Mr. Hill's CAPM range will be understated and should move closer to 10.00% as opposed to the 9.16% to 9.58% shown on Exhibit SGH-1, Schedule 7 of his testimony.

Individually, our differences of opinion with Mr. Hill over specific inputs to his DCF and CAPM models are not overly large. However, taken together and if were to ultimately decide to recommend that the Commission continue its practice of allowing a common equity flotation cost adjustment within ROE, then these small differences could amount to something approaching 30 to 40 basis points.

VII. SALES FORCAST

This section of the Bench Analysis describes our findings with respect CMP's sales forecast. Our analysis demonstrates that higher residential sales should be used to establish distribution rates and to evaluate CMP's financial performance under ARP 2008 than reflected by the Company's sales forecast. For example, for 2008, our forecast of residential sales is 2.77% above CMP's original forecast and 4.13% above CMP's revised forecast (*In response to data request OPA-04-16, CMP revised its residential, commercial and industrial forecasts to reflect new demand side savings data*

from Efficiency Maine. From this point on, references to CMP forecasts are to these revised versions.) With respect to the commercial and industrial sectors, our forecasts are comparable to CMP's. We have presented a summary of our sales forecast analysis in this section of the Bench Analysis. Further details are included as Appendix SALES 1 and Appendix SALES 2.

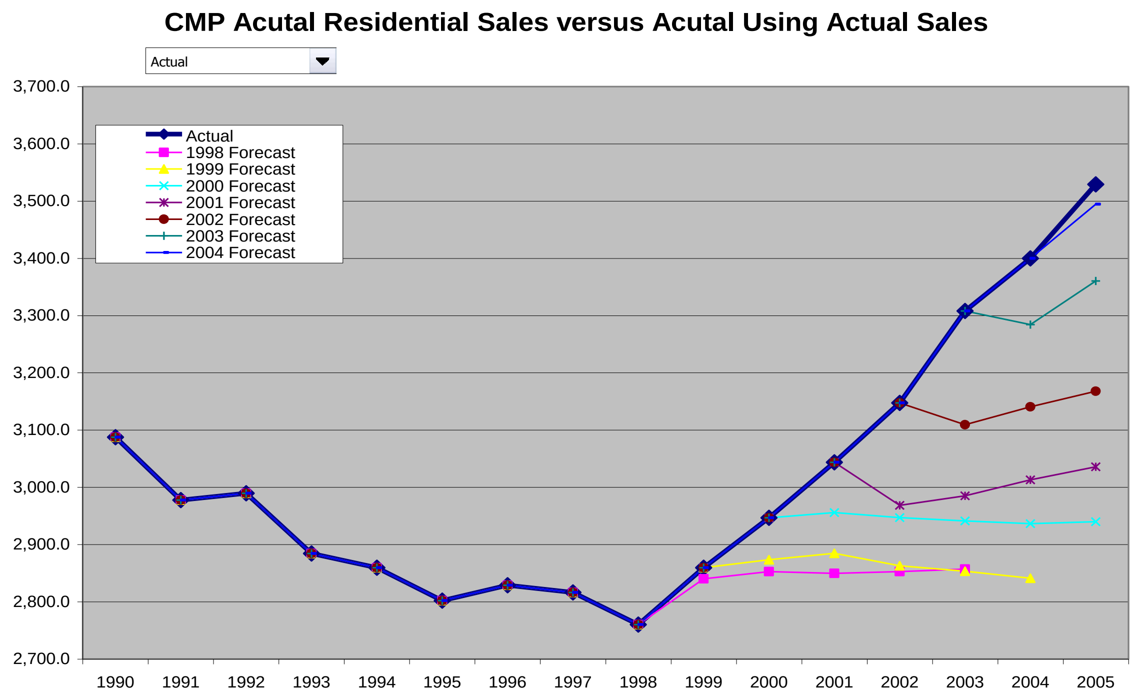
A. Description of General Approach to Forecast Analysis

CMP's sales forecasts have been a major issue in rate and ARP cases for many years due their importance in determining ultimate rate levels. In this proceeding, CMP has presented not only its own internal forecast expert, but has also retained consultants who have supported its forecasting approach as being consistent with "good utility practice".

Given the inherent uncertainty and judgment that is part of the sales forecasting process, and the importance of the issue to the Commission's decisions in this case, the Staff has critically examined CMP's sales forecasts. In analyzing sales forecasts, we do not question the effort made by CMP nor the integrity of their statistical analysis. Indeed, the Company has been helpful in providing data and other information regarding its forecast. However, given the many areas of judgment that must necessarily go into the sales forecast, we have carefully analyzed the forecasts for potential biases in the selection of variables, time periods, forecast data or other factors that could cause rates to be higher than they ought to be.

In past cases we have used various approaches to review CMP's sales forecasts. For example, in the 2001 stranded investment case we reviewed the details of CMP's end use model and made some changes that produced an alternative

forecast. In Docket No. 2002-770 we developed a trend forecast rather than delving into the econometric equations, the end-use saturation data and the voluminous customer interviews. Finally, in Docket No. 2005-729, we analyzed the accuracy of CMP's forecasts in terms of their ability to predict actual sales. The graph below illustrates the performance of CMP's historic forecasts that formed the basis of our concern in that case.



Given the apparent downward bias in CMP's sales predictions as evidenced by the graph above, in that case we investigated whether a completely different forecast should be used as an alternative to CMP's.

In past cases, we have focused on specific elements of CMP's end use forecast or, alternatively, we have attempted to derive alternative forecasts from trends or the EIA. However, given the fact that CMP's model did indeed predict 2006 sales

better than the EIA forecast or the adjusted trend forecast, and because of CMP's increasing reliance on econometric models, we have devoted most of our effort in this case to analyzing the econometric equations that underlie CMP's sales forecasts and developing alternative forecasts using similar econometric methods. The results of our forecasts are summarized below.

B. Residential Sales

After studying the details of CMP's residential econometric models, we have come to the conclusion that the Commission should not rely on CMP's sales forecast when setting distribution rates and evaluating financial returns generated from CMP's proposed ARP, particularly with respect to the residential sales forecast. The tables below summarizes the results of a residential sales forecast that we believe contains more reasonable economic theory, statistical analysis and forecasting data than CMP's model.

Summary of CMP and Staff Residential Sales

	CMP Sales Revised	Growth vs Prior Year	Satff Sales	Growth vs Prior Year
2005	3,529,121		3,529,121	
2006	3,431,361	-2.8%	3,431,361	-2.8%
2007	3,397,940	-1.0%	3,494,435	1.8%
2008	3,371,253	-0.8%	3,510,390	0.5%
2009	3,362,619	-0.3%	3,545,106	1.0%
2010	3,413,165	1.5%	3,567,932	0.6%

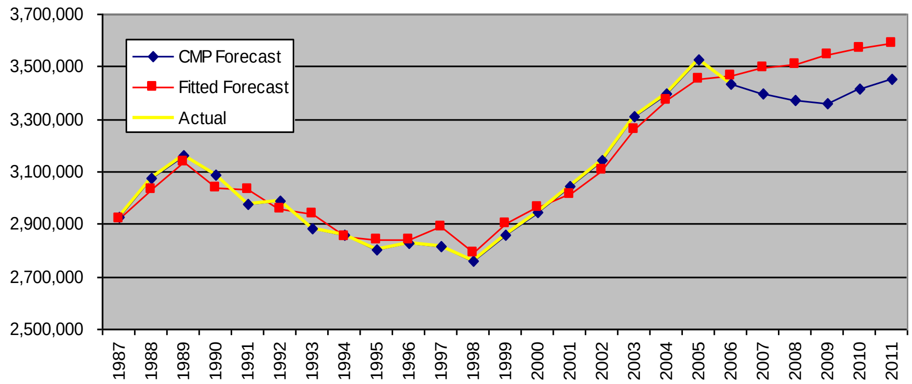
As shown below, the Staff residential forecast indicates a compound annual growth rate in residential sales of 1.21% from low 2006 levels until 2010 (the growth rate is affected by the relatively low levels of 2006 sales.) In its forecast, CMP projects a growth rate in residential sales of .09% over the period 2006 to 2010. Indeed, for 2007 as compared to 2006, our 2.8% growth rate is consistent with actual

sales for the first half of 2007. CMP's forecast, in contrast, appears to underestimate sales for this period. In comparison to the forecasts, the actual growth rate in residential sales averaged 2.23% for the period 1996 to 2005.

CMP Revised Forecast with Updated DSM						Staff Forecast	
Year	Forecast Use per Customer	Number of Customers	CMP Sales Forecast Prior to DSM	Less: CMP DSM	Total Sales	Alternative Forecast	Percent Difference vs CMP
2007	6,423	2,149	3,450,819	52,879	3,397,940	3,494,435	2.84%
2008	6,375	2,173	3,462,911	91,658	3,371,253	3,510,390	4.13%
2009	6,376	2,196	3,500,655	138,036	3,362,619	3,545,106	5.43%
2010	6,494	2,219	3,602,705	189,540	3,413,165	3,567,932	4.53%
2011	6,598	2,241	3,697,192	243,513	3,453,678	3,589,913	3.94%
1996 Sales	6,081	1,865	2,835,441		2,835,441	2,835,441	
2005 Sales	6,605	2,094	3,458,194		3,458,194	3,458,194	
2006 Sales	6,406	2,124	3,400,516		3,400,516	3,400,516	
CAGR 1996-2005	0.92%	1.29%	2.23%		2.23%	2.23%	
CAGR 1996-2006	0.52%	1.30%	1.83%		1.83%	1.83%	
CAGR 2006-2010	0.34%	1.11%	1.45%		0.09%	1.21%	
CAGR 2005-2010	0.27%	0.88%	1.16%		0.07%	0.97%	

The manner in which our forecast of residential use per customer compares to CMP's forecast and to historic use per customer is shown on the graph below. For the years prior to 2007, the lines on the graph show the actual level of use per customer and the use per customer fitted by the regression equation. For the year 2007 and later, the graph shows the forecast of use per customer that we developed relative to CMP's forecast.

Forecast Ln Use: Pre DSM Pre Space
Versus Log Alt Real Price and Log of Global Insight and others

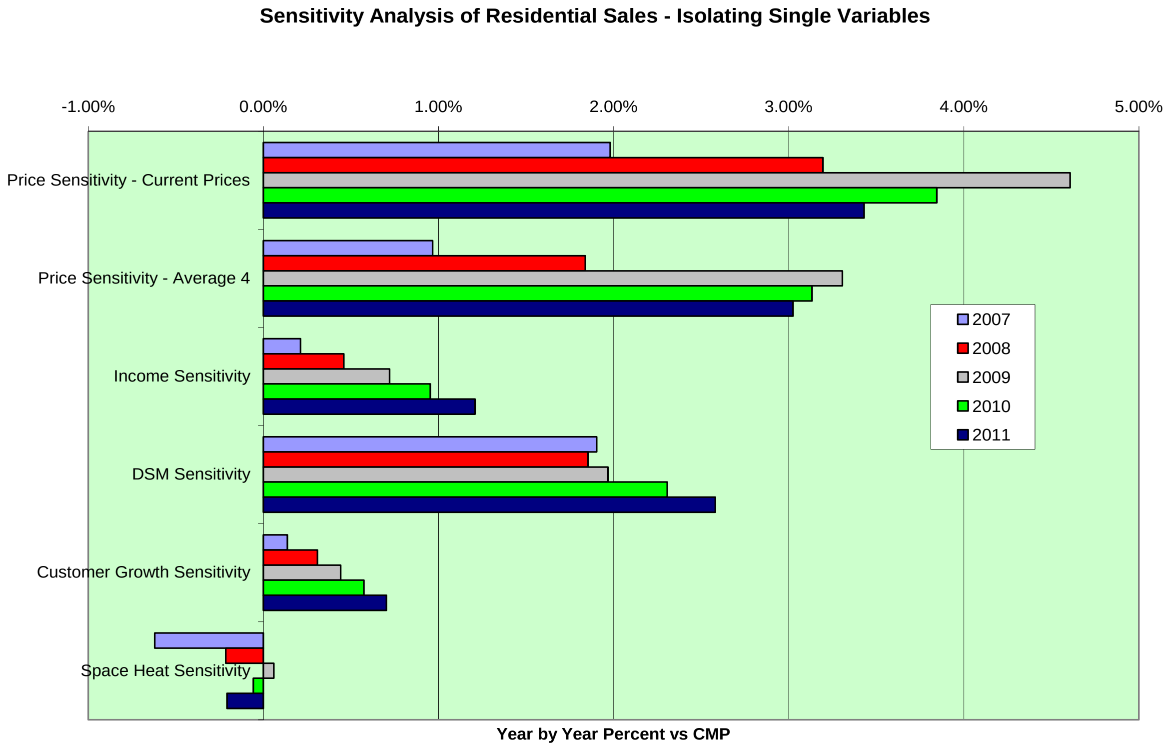


Reasons that the residential sales projection shown in the table and graph above produce higher forecasts than those developed by CMP are summarized below and explained in further detail in Appendix SALES 1. A summary of the various factors that drive the alternative forecast results include:

- Accounting for the fact that historic DSM programs administered by both CMP and Efficiency Maine have affected the level of CMP's residential sales, but are omitted variables in CMP's regression;
- Recognizing that consumers do not ignore current prices when making decisions on use by computing price elasticity using current prices or average prices over the past four quarters.
- Adjusting the forecasted prices to more accurately reflect prospective changes in distribution tariffs.

- Reflecting the effect of changes in space heat use that were omitted from CMP’s regression analysis.
- Incorporating the Global Insight forecast for disposable income per capita in the regression equation rather than CMP’s adjusted income variable.
- Using lagged housing starts and an alternative equation for predicting the number of new customers.
- Removing the air conditioning saturation variable and replacing the humidity adjusted cooling degree days with cooling degree days.

The graph and table below shows which of the factors mentioned above have the largest effect on the variance between CMP’s forecast and our forecast. The scale on the graph shows the effect of each factor in isolation on the percent difference between our forecast and CMP’s forecast. In developing this graph we always begin with the CMP forecast and then change one factor at a time to show how that single factor affects the sales forecast. The table below the graph simply lists the percent changes in sales relative to CMP that are displayed on the graph as well as the baseline forecast that combines all of the factors.



Residential Equation Scenario Analysis					
Year	2007	2008	2009	2010	2011
Scenario					
CMP Case	0.00%	0.00%	0.00%	0.00%	0.00%
Baseline Case	**2.84%**	**4.13%**	**5.43%**	**4.53%**	**3.94%**
Price Sensitivity - Current Prices	1.98%	3.20%	4.61%	3.85%	3.43%
Price Sensitivity - Average 4	0.97%	1.84%	3.31%	3.13%	3.03%
Income Sensitivity	0.21%	0.46%	0.72%	0.95%	1.21%
DSM Sensitivity	1.90%	1.85%	1.97%	2.31%	2.58%
Customer Growth Sensitivity	0.14%	0.31%	0.44%	0.57%	0.70%
Space Heat Sensitivity	-0.62%	-0.22%	0.06%	-0.06%	-0.21%
Cooling Degree Day Sensitivity	0.0%	0.0%	0.0%	0.0%	0.0%

Because developing a sales forecast involves judgment and there is uncertainty as to how historic relationships will play out in the future, we do not assert that our forecast is the only possible way to project CMP's residential sales. Therefore, we have developed a number of alternative scenarios that could be plausible. The

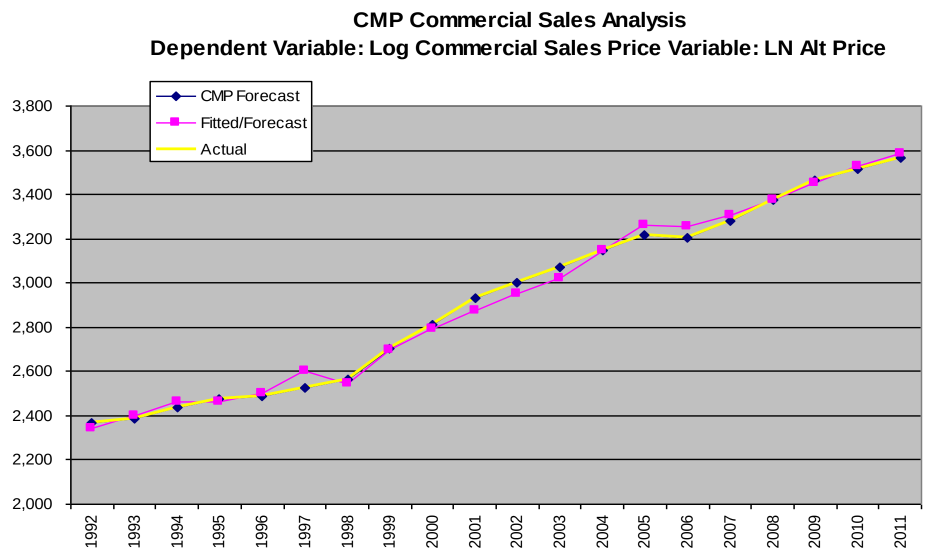
effect of selected scenarios on the forecast relative to CMP's forecast are shown in the table below. Data that are shaded represent scenarios in which the alternative scenario exceeds our base case scenario. The table demonstrates that there are many alternative reasonable scenarios that generate an even higher forecast than our baseline forecast and thereby confirms the reasonableness of our baseline case. Additional scenarios that evaluate use of different time periods are presented in the detailed discussion of the residential equation.

Residential Equation Scenario Analysis					
Year	2007	2008	2009	2010	2011
Scenario					
CMP Case	0.00%	0.00%	0.00%	0.00%	0.00%
Baseline Case	**2.84%**	**4.13%**	**5.43%**	**4.53%**	**3.94%**
Scenario 1: Include Space Heat	4.33%	5.93%	8.14%	8.00%	8.29%
Scenario 2: Price Variable with Average of Four Quarters	2.01%	2.99%	4.31%	3.87%	3.50%
Scenario 3: CMP Modeling of DSM	4.02%	5.62%	7.99%	7.78%	7.91%
Scenario 4: Air Conditioning Variable Included	2.68%	3.99%	5.49%	4.62%	4.01%
Scenario 5: Exclude 1st and 2nd Dummies	2.85%	4.06%	5.32%	4.39%	3.77%
Scenario 6: CMP Customer Equation	2.70%	3.81%	4.98%	3.96%	3.24%
Scenario 7: Average Price and Include Space Heat	2.90%	3.98%	6.21%	6.85%	7.50%
Scenario 8: Average Price, Space Heat and CMP DSM	0.56%	1.38%	3.15%	3.37%	3.66%
Scenario 9: A/C, Average Price, Space Heat and CMP DSM	0.55%	1.44%	3.30%	3.59%	3.86%
Scenario 10: Space Heat and A/C Included	4.39%	6.22%	8.82%	8.86%	9.24%
Scenario 11: Space Heat and No Dummies	4.31%	5.90%	8.05%	7.89%	8.16%

C. Commercial Sales

CMP's commercial sales forecast which was derived in part from interviews with individual customers does not have the same declining trend as its residential forecast. Rather that analyze the details of each of CMP account manager's interviews with individual customers, we have constructed an alternative commercial sales projection using econometric equations. In developing this equation we analyzed a series of separate factors similar to the manner in which we evaluated the residential

equation. The graph below that shows the results of an alternative forecast we have constructed using econometric analysis. This demonstrates that CMP projects sales to grow from the 2006 base, but the forecast does not rebound from the relatively low level of sales experienced in 2006. The forecast we developed from a detailed analysis of variables that affect commercial sales produces results that are similar to the forecasts developed by CMP.



CMP's forecast of commercial sales results in a compound annual growth rate of 2.2% for the period 2005 and 2010, which compares to historic growth rates of 2.9% and 2.2% for the periods 1996-2006 and 1996-2005. Before the DSM adjustment, CMP sales forecast results in a growth forecast of 2.7% for the 2005-2010 time period. As shown in the table below, this pre-DSM forecast is consistent with historic trends.

CMP Commercial Sales Forecast - Update

	Sales Forecast without DSM	Less: DSM	Total Sales	Alternative Econometic Forecast
2007	3,305	27	3,279	3,302
2008	3,435	47	3,388	3,390
2009	3,574	68	3,506	3,498
2010	3,681	90	3,592	3,602
2011	3,795	111	3,684	3,702
CAGR 1996-2005	2.9%		2.9%	
CAGR 1996-2006	2.6%		2.6%	
CAGR 2005-2010	2.7%		2.2%	
CAGR 2006-2010	3.5%		2.9%	

Our base case forecast is somewhat above the CMP projection. However, reasonable alternative forecasts produce results that are slightly lower than CMP's forecast Given the similarity of the econometric approach and CMP's survey approach, we recommend adopting CMP's updated commercial forecast with a slight adjustment for distribution prices. The commercial forecast is shown in the table below.

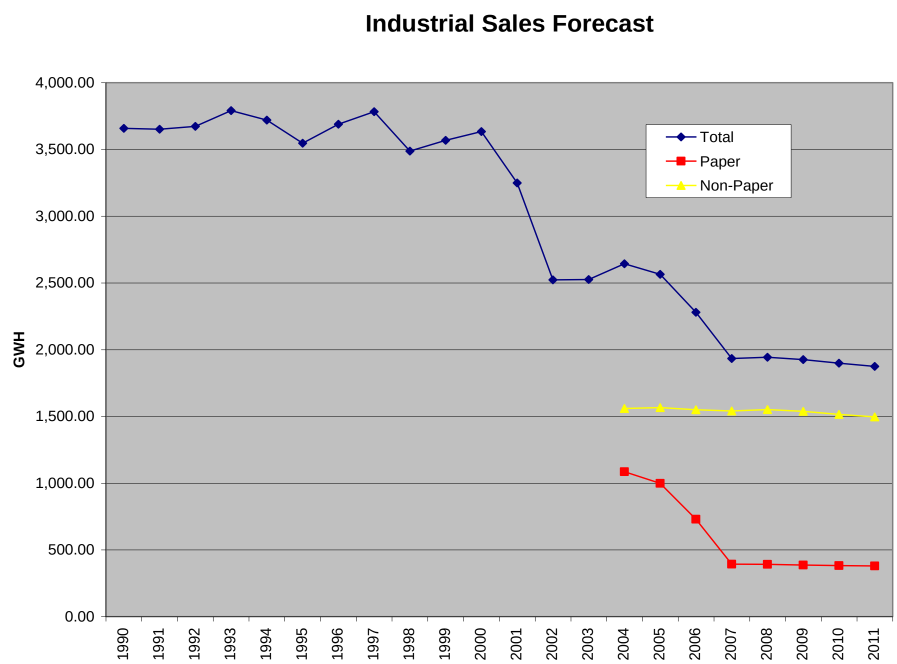
Adjusted Commercial Forecast

	Percent Difference in Price	CMP Price Elasticity	Percent Change in Sales	Alternative Commecial Forecast Pre DSM	Updated Commercial DSM	Commercial Sales Forecast
2007	0.00%	-0.100216	0.00%	3,305.17	26.64	3,278.54
2008	-0.61%	-0.100216	0.06%	3,437.11	47.49	3,389.63
2009	-1.03%	-0.100216	0.10%	3,577.89	68.16	3,509.73
2010	-1.61%	-0.100216	0.16%	3,687.43	89.50	3,597.93
2011	-1.89%	-0.100216	0.19%	3,801.80	111.04	3,690.76

Industrial

Because CMP's industrial customers contribute very little to distribution revenue, the forecast is of much less importance in this case than the residential and commercial forecasts. For simplicity, we have used CMP's forecast for the financial analysis and modeling discussed in Section VIII.

CMP develops its industrial forecast primarily using surveys of individual customers. The industrial forecast is illustrated on the graph below.



Because of the historic trends in industrial sales, it is more difficult to evaluate CMP's forecast using econometric analysis; indeed, once paper sales are removed, the trend is essentially flat. Further, CMP has provided little basis upon which to objectively assess whether the individual customer surveys are objective and accurate. To objectively assess bias in the surveys, the accuracy of historic surveys relative to realized sales would have to be assessed on a customer by customer basis

and on an aggregate basis. Finally, by focusing on existing customers without recognizing that new customers can be added, the Company's approach has a natural downward bias.

While the flat historic trends and the lack of transparency in surveys make the industrial forecast very difficult to analyze in practice, as noted above the industrial forecast is less significant in evaluating CMP's financial performance under the ARP. The average rate per kWh for industrial customers is only about twelve percent of the residential price and much of industrial revenue comes from customer charges. Finally, as with the commercial sales forecast, CMP reduced the industrial sales forecast due to revised Efficiency Maine savings estimates. Despite the natural downward bias in CMP's approach, given the difficulty of evaluating the industrial forecast, we have not changed the industrial forecast after the DSM update.

D. Trends in Recent Sales

The fundamental issue with respect to residential sales growth involves whether historic trends in increasing sales that occurred for the seven years from 1999 through 2005 will reverse – CMP's position – or alternatively whether the growth trends realized from 1998 through 2005 will continue. In 2006, residential sales declined for the first year since 1998 before which CMP experienced flat or declining sales for a number of years. In this section we discuss a variety of detailed econometric issues, but the basic central question boils down to whether the decline in sales from 2005 to 2006 is indicative of a permanent long-term trend, or, alternatively whether the 2006 decline was a temporary blip and the strong sales growth experienced by CMP over the past decade will continue. This means that while complex econometric equations may

have an appropriate place in forecasting sales, the starting point should be an understanding of why sales increased for seven years from 1999 through 2005, why sales declined in the 1990's and why sales declined in 2006. If we understand the root causes of changes in sales, we can then assess whether we expect similar factors to affect future sales. To address this question, we begin by presenting an analysis of 2006 sales relative to 2007 and to earlier years.

In this section we analyze some of the factors that resulted in sales for 2006 declining relative to the sales in 2005 and we evaluate the sales levels that have been experienced in the first half of 2007. Our discussion is divided into three sub-sections. The first sub-section describes how CMP's projections compare to actual and weather adjusted sales for the first half of 2007. The second sub-section evaluates the effects of weather on the low level of residential sales experienced by CMP in 2006. The third sub-section reviews the issue of whether other entities project a structural change in residential electricity sales trends after declines experienced in 2006.

E. Actual 2007 Sales versus CMP Forecast

As stated above, a fundamental issue in making a residential sales forecast in this case is determining whether the decline in sales from 2005 to 2006 is indicative of a long-term trend or whether the decline was a temporary blip. This issue can partially be tested through evaluating whether sales in 2007 have continued the downward trends experienced in 2006 or whether the sales level has rebounded. The analysis below shows that for the first half of 2007, CMP's sales are 3% above first half of 2006 levels and 2.9% above CMP's adjusted forecast.

In response to a data request, CMP provided monthly residential sales on a weather adjusted and non-weather adjusted basis for the first six months of 2007. The two tables below use this data to compare actual sales with the CMP forecasts and actual 2007 sales with actual 2006 sales. The data demonstrates that actual weather adjusted sales have exceeded CMP's projection by 2.9% and that 2007 residential sales are 3% above 2006 sales.

2007 versus 2006 Residential Sales

	2006 Actual Sales (MWH)	2007 Actual Residential (MWH)	2007 Weather Normalized Sales (MWH)	Percent Actual 2007 verus 2006	Percent Weather Adjusted 2007 verus 2006
January	334,985	325,031	337,621	-3.0%	0.8%
February	290,537	327,344	321,839	12.7%	10.8%
March	303,300	318,219	311,407	4.9%	2.7%
April	267,795	284,452	281,836	6.2%	5.2%
May	238,203	248,452	249,812	4.3%	4.9%
June	273,831	255,847	258,921	-6.6%	-5.4%
Six Month Total	**1,708,651**	**1,759,345**	**1,761,436**	**3.0%**	**3.1%**

Actual 2007 Residential Sales versus Updated Forecast

	Quarter	2007 Actual Residential (MWH)	Less: Added DSM in Update (MWH)	Updated Forecast (MWH)	Percent Original Forecast vs Actual 2007	Percent Updated Forecast vs Actual 2007	2007 Weather Normalized Sales (MWH)	Percent Original Forecast vs Normal Weather	Percent Updated Forecast vs Normal Weather
January	1	325,031	2,088	328,325	-1.6%	-1.0%	337,621	2.2%	**2.8%**
February	1	327,344	2,088	314,449	3.4%	4.1%	321,839	1.7%	**2.4%**
March	1	318,219	2,088	303,222	4.2%	4.9%	311,407	2.0%	**2.7%**
April	2	284,452	2,088	267,948	5.3%	6.2%	281,836	4.4%	**5.2%**
May	2	248,452	2,088	247,006	-0.3%	0.6%	249,812	0.3%	**1.1%**
June	2	255,847	2,088	251,404	0.9%	1.8%	258,921	2.1%	**3.0%**
Six Month Total		**1,759,345**	**12,530**	**1,712,353**	**2.0%**	**2.7%**	**1,761,436**	**2.1%**	**2.9%**

F. Effect of Weather on 2006 Residential Sales

In 2006, CMP's residential sales declined by 2.8% relative to 2005 annual sales. CMP asserts that the 2006 sales reflect normal weather. Further CMP declares that given lower housing prices, higher electricity prices and a poor economy these negative factors will continue into the future. For example, with respect to the level of 2006 residential sales, Mr. Duvalis stated that: "On a net basis, there was little kWh impact of the abnormal weather that occurred in 2006."

In analyzing why CMP's sales declined from 2005 to 2006 we have made an independent assessment of how weather conditions affected the level of 2006 sales. The tables below present month by month actual sales for 2005, 2006 and for the first six months of 2007 along with monthly heating and cooling degree days for the three years. The tables demonstrate that heating degree days in 2006 were 12% below heating degree days in 2005, 11% below heating degree days over the period 2000-2005 and 10% below heating degree days over the period 1997-2005. (Since heating degree days are calibrated to 65 degrees Fahrenheit, and since people in Maine do not really begin using space heat until the temperature is much colder, the variable may be biased. This issue is discussed in Appendix SALES 2.)

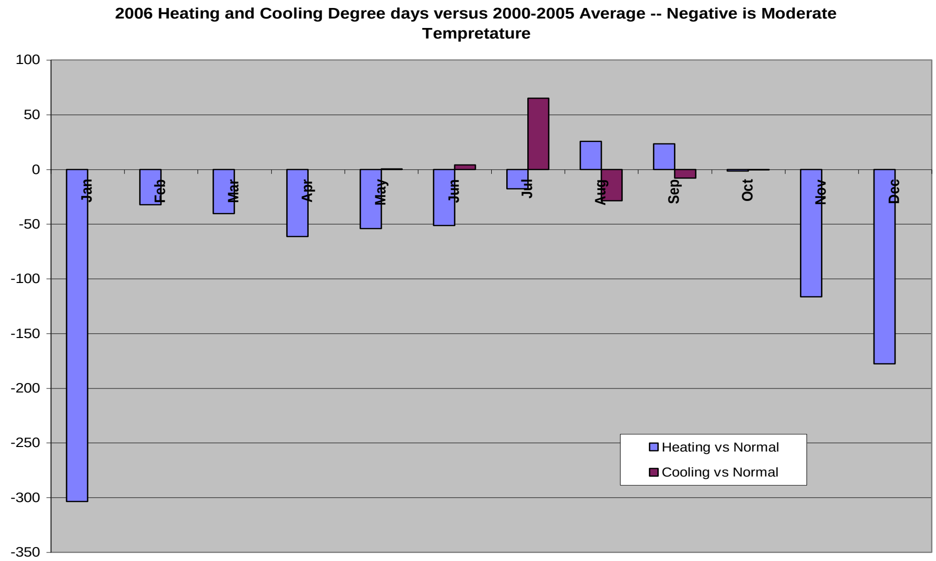
Analysis of 2006 Heating Degree Days								
	2005	2006	2007	Average 1997-2005	Average 2000-2005	2006 vs 2005	2006 vs Average 1997-2005	2006 vs Average 2000-2005
January	1,410	1,068	1,206	1,332	1,372	32.0%	-19.8%	-22.1%
February	1,099	1,089	1,273	1,075	1,121	-0.9%	1.3%	-2.9%
March	1,074	937	1,012	967	977	-12.8%	-3.1%	-4.1%
April	596	575	689	631	637	-3.5%	-8.8%	-9.7%
May	477	324	295	364	378	-32.1%	-11.0%	-14.3%
June	100	64	101	114	115			
July	17	-		14	18			
August	8	43		17	17			
September	85	149		130	126	75.3%	14.4%	18.7%
October	454	491		506	493	8.1%	-2.9%	-0.3%
November	723	630		754	747	-12.9%	-16.4%	-15.6%
December	1,146	940		1,091	1,118	-18.0%	-13.9%	-15.9%
Total	7,189	6,310		6,997	7,117	-12.2%	-9.8%	-11.3%
Total First Half	4,756	4,057	4,576	4,484	4,600	-14.7%	-9.5%	-11.8%

Cooling degree days were also lower in 2006 than 2005 by 11%, as shown below, although cooling degree days in 2006 were higher than the average of earlier years. The single month where cooling degree days were higher in 2006 than in 2005 was July. In that month, despite the higher cooling degree days in 2006 relative to 2005, sales were lower.

Analysis of 2006 Cooling Degree Days								
	2005	2006	2007	Average 1997-2005	Average 2000-2005	2006 vs 2005	2006 vs Average 1997-2005	2006 vs Average 2000-2005
January	-	-	-	-	-			
February	-	-	-	-	-			
March	-	-	-	0	-			
April	-	-	-	-	-			
May	-	9	22	5	4			
June	97	73	66	73	72	-24.7%	0.5%	0.9%
July	159	224		136	121	40.9%	64.2%	85.9%
August	174	110		139	146	-36.8%	-20.7%	-24.8%
September	52	16		31	32	-69.2%	-48.2%	-50.5%
October	2	-		2	3			
November	-	-		-	-			
December	-	-		-	-			
Total	484	432		387	379	-10.7%	11.8%	14.0%
Total First Half	97	82	88	78	77	-15.5%	5.1%	7.2%

The graph below illustrates heating and cooling degree days in 2006 relative to the five year average for 2000-2005. With the exception of July, the graph

shows that weather was more moderate in each month of the year compared to the average for the earlier five years.



We have used data provided by CMP on monthly sales and degree days from 1997 through 2006 to analyze the effects of weather on 2006 sales. The 2006 sales relative to 2005 and 2007 are shown on the table below which demonstrates that 2006 sales declined by 2.8% in 2006 relative to 2005 levels.

Analysis of 2006 Residential Sales (MWH)

	2005	2006	2007	Average 1997-2005	Average 2000-2005	2006 vs 2005	2006 vs Average 1997-2005	2006 vs Average 2000-2005
January	338,027	334,985	325,031	304,941	317,037	-0.9%	9.9%	5.7%
February	309,978	290,537	327,344	281,466	293,675	-6.3%	3.2%	-1.1%
March	313,954	303,300	318,219	269,300	282,214	-3.4%	12.6%	7.5%
April	282,142	267,795	284,452	250,097	258,127	-5.1%	7.1%	3.7%
May	245,229	238,203	248,452	227,185	235,324	-2.9%	4.8%	1.2%
June	266,076	273,831	255,847	227,066	238,176	2.9%	20.6%	15.0%
July	317,545	313,794		255,575	270,489	-1.2%	22.8%	16.0%
August	304,937	312,703		260,462	275,668	2.5%	20.1%	13.4%
September	297,829	286,800		253,477	267,671	-3.7%	13.1%	7.1%
October	265,249	244,789		230,326	237,767	-7.7%	6.3%	3.0%
November	274,325	263,966		246,701	257,716	-3.8%	7.0%	2.4%
December	313,829	300,658		283,537	295,292	-4.2%	6.0%	1.8%
Total	3,529,120	3,431,361		3,090,133	3,229,155	-2.8%	11.0%	6.3%
Total First Half	1,755,406	1,708,651	1,759,345	1,560,055	1,624,553	-2.7%	9.5%	5.2%

Our analysis of the effect of weather on 2006 sales applies monthly dummy variables as well as interaction terms, monthly days read, trend factors, prices and other factors to create an equation for monthly sales as a function of the heating degree days and cooling degree days. Once this equation is established, we have computed the fitted or expected value of 2006 sales using: (1) actual 2006 heating and cooling degree days; (2) 2005 actual heating and cooling degree days; (3) the average heating and cooling degree days for the five year period 2000-2005; and (4) heating degree days for the period 1997-2005. This process enables one to isolate the effect of weather on 2006 sales. The fitted value of sales for 2006 using 2006 weather versus the fitted value using alternative weather conditions from other years is shown in the table below.

Analysis of Weather Effect on 2006 Sales		
	MWH Sales	Percent versus 2006 Fitted
Actual 2006 Sales	3,431,361	
Fitted 2006 Sales	3,456,292	
Fitted 2006 with 2005 Weather	3,535,115	2.28%
Fitted 2006 with 2000-2005 Weather	3,500,715	1.29%
Fitted 2006 with 1997-2005 Weather	3,500,655	1.28%

Mr. Duvalis testified that "in Docket No. 2005-729, the Bench Analysis recommended a residential forecast of 3,532 million kWh be adopted for 2006. In hindsight, the Staff's forecast overestimated 2006 residential sales by 100 million kWh, or by 2.9%." (The 2.9% was similar to the percentage decline in actual sales from 2005

to 2006.) The above table demonstrates that weather was in fact a significant factor in explaining why 2006 sales declined relative to sales in earlier periods and why the forecast derived from the EIA underestimated sales. The table shows that 2.3% out of the 2.8% decline from 2006 from 2005 was due to weather. In otherwords, if 2006 weather had been comparable to 2005, 2006 residential sales would have been 2.3% higher, and the EIA-based forecast would have overstated sales by much less (about 0.6%).

G. Regional and Nationwide Trends and Outlooks

In the final part this section we investigate whether forecasts of electricity sales on a region-wide and a national basis have similar trends as the CMP forecast. We do not advocate using other sources as the basis for our projection of CMP sales as we did in the last case. Instead, we include this analysis to discern: (1) whether similar declines in 2006 sales such as those experienced by CMP have occurred elsewhere; and (2) to the extent that decreasing sales have occurred, whether the 2006 declines are expected to be temporary blips or permanent trends.

The table below shows historic and projected data reported by the EIA for the New England region. In this table, actual sales are recorded through July 2007 and the remaining figures are projected. The 4.65% decline in annual sales for 2006 relative to 2005 for New England was even greater than the decline realized by CMP. For the year 2007, EIA expects sales to rebound from the 2006 decline. The comparison of 2008 relative to 2007 for months after July illustrates that EIA expects sales growth of about 1.90%. By contrast, the growth rate from 2007 to 2008 in our baseline forecast of residential sales is only 0.46%.

EIA Historic and Projected Data for New England Region
MWH per Day

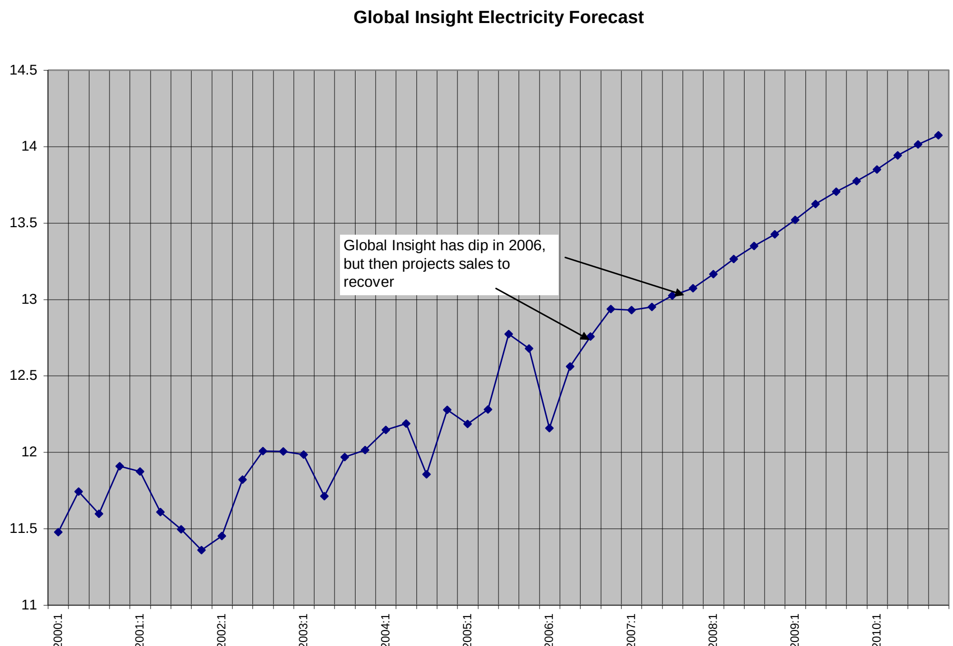
	2004	2005	2006	2007	2008	2006 vs 2005	2007 vs 2006	2008 vs 2007
January	160.00	149.44	142.39	141.62	154.63	-4.72%	-0.54%	9.19%
February	142.01	138.25	134.67	155.80	143.85	-2.59%	15.69%	-7.67%
March	123.35	133.55	128.98	137.15	131.85	-3.42%	6.34%	-3.86%
April	113.69	110.14	105.63	119.81	115.34	-4.09%	13.43%	-3.73%
May	104.06	105.83	104.69	112.64	108.41	-1.08%	7.60%	-3.76%
June	121.95	132.91	127.79	126.56	125.98	-3.85%	-0.96%	-0.46%
July	129.46	156.37	160.00	145.84	153.17	2.32%	-8.85%	5.02%
August	138.62	158.72	149.84	153.25	156.09	-5.60%	2.28%	**1.85%**
September	122.95	128.39	112.20	125.01	127.37	-12.61%	11.42%	**1.89%**
October	107.94	114.45	107.53	111.21	113.32	-6.05%	3.43%	**1.90%**
November	120.96	120.18	117.94	121.90	124.21	-1.87%	3.36%	**1.90%**
December	146.17	152.01	134.21	147.66	150.46	-11.71%	10.02%	**1.90%**
Total	1,531.17	1,600.24	1,525.86	1,598.47	1,604.71	-4.65%	4.76%	0.39%
Percent Change		4.51%	-4.65%	4.76%	0.39%			

The decline in sales and subsequent rebound is present for the entire U.S. as well as for the New England region. The table below demonstrates that residential sales declined by .38% in 2006 relative to 2005 and that sales are projected to increase by about 2% in 2008.

EIA Historic and Projected Data for U.S.
MWH per Day

	2004	2005	2006	2007	2008	2006 vs 2005	2007 vs 2006	2008 vs 2007
January	4,101	4,042	3,888	4,042	4,284	-3.80%	3.96%	5.99%
February	3,878	3,810	3,740	4,343	4,075	-1.81%	16.12%	-6.18%
March	3,192	3,357	3,393	3,423	3,507	1.09%	0.88%	2.44%
April	2,846	2,892	2,983	3,022	3,103	3.17%	1.30%	2.67%
May	2,923	2,819	3,039	3,126	3,122	7.82%	2.86%	-0.14%
June	3,745	3,888	3,966	3,973	4,007	2.01%	0.18%	0.85%
July	4,171	4,661	4,768	4,608	4,780	2.31%	-3.36%	3.74%
August	4,078	4,739	4,851	4,732	4,826	2.37%	-2.46%	**1.98%**
September	3,745	4,217	3,870	4,133	4,214	-8.23%	6.79%	**1.97%**
October	3,015	3,312	3,114	3,262	3,327	-6.00%	4.76%	**2.01%**
November	2,988	3,056	3,168	3,191	3,257	3.67%	0.71%	**2.07%**
December	3,676	3,877	3,717	3,906	3,987	-4.12%	5.08%	**2.09%**
Total	42,357	44,668	44,498	45,761	46,488	-0.38%	2.84%	1.59%
Percent Change		5.46%	-0.38%	2.84%	1.59%			

The graph below presents historic and projected data for total electricity sales to ultimate customers prepared by Global Insight for the entire U.S. This graph shows that while there was in blip in 2006 sales, the long-term outlook is generally consistent with historic trends. This contrasts with CMP's residential outlook where sales per customer remains flat or declines and does not continue trends that have occurred since the late 1990's.



VIII. FINANCIAL MODELING

A. Summary of Financial Modeling

In this section we summarize our modeling as it relates to the recommendations contained in this Bench Analysis. The Staff used the Company's financial model, with certain modifications, to develop our revenue requirement recommendation and to model the financial consequences of the various alternative rate plan proposals. In addition, the Staff ran several sensitivities or alternative cases to demonstrate expected outcomes under different sets of assumptions.

Based on Staff's Base Case set of assumptions, including our recommended sales forecast; cost of capital; vegetation management spending; ROE and capital structure; treatment of acquisition premium; and the many other issues discussed in the Bench Analysis, without a starting point rate decrease (as proposed by CMP), CMP would over-earn by $40 million in the rate-effective year, and by $158 million over the term of a 5-year ARP.[21] Even if one assumes CMP's load forecast is correct, CMP would over-earn by $32 million in the rate year and $130 million over the 5-year term. The results of the Base Case and other key cases are summarized below. A more detailed summary of these and other Cases is provided in Appendix CASES.

Staff Base Case							
Revenue Requirements			$194,363	$197,658	$201,304	$203,619	$796,944
Staff Base Case Revenues		*16.91%*	$194,363	$198,097	$201,195	$204,349	$798,004
Rev. Above/(Below RR)			$0	$439	($109)	$730	$1,060
ROE			*9.8%*	*9.9%*	*9.8%*	*10.0%*	*9.9%*
Revenues if no Reduction		*0.00%*	$233,920	$237,346	$240,217	$243,132	$954,616
Over/Under Earning with no Adjustment			$39,557	$39,688	$38,913	$39,513	$157,672
ROE			24.4%	24.1%	23.6%	23.5%	23.9%
Staff Base Case with CMP Sales							
ROE							
Revenue Requirements			$194,363	$197,658	$201,304	$203,619	$796,943
Staff Base Case Revenues		*16.91%*	$187,965	$191,525	$195,675	$199,730	$774,895
Rev. Above/(Below RR)			($6,398)	($6,133)	($5,629)	($3,889)	($22,048)
ROE			*8.40%*	*8.48%*	*8.61%*	*8.99%*	*8.62%*
Revenues if no Reduction		*0.00%*	$226,219	$229,471	$233,625	$237,635	$926,949
Over/Under Earning with no Adjustment			$31,856	$31,813	$32,321	$34,016	$130,006
ROE			*22.51%*	*22.23%*	*22.09%*	*22.20%*	*22.26%*

[21]These calculations do not include spending for CMP's 5-year cycle trim program which the Staff has recommended subject to recovery under an accounting order.

The modifications we made relative to CMP's filling fall into two broad categories. First, the Staff made several minor technical changes to correct what appear to be errors in the Company's filing. Second, the Staff changed several of the inputs to the model to reflect assumptions we consider to be more reasonable. These changes, and the reasons that underly them, are discussed below and throughout the Bench Analysis. Overall, the Staff changes reduce the rate year revenue requirement (as compared to the Company's filing) by $38 million. Over the five-year term of Staff ARP III proposal, the changes reduce required revenues by $205 million.

In the following section, we summarize the changes reflected in our Base Case. For most of these changes, the rationale and support is presented in other sections of the Bench Analysis.

B. Technical Changes/Corrections

a) O&M expense change (T-1) – The Company forecast O&M expenses by applying discrete cost escalators to certain expenses and allowing the other expenses to increase at inflation. However, in its most recent calculation of the forecast O&M expenses (ODR-01-17 Supplemental), the O&M totals were hard-wired into the spreadsheet and the discretely forecast expenses were subtracted from the totals to obtain the remaining O&M expenses. As a result, the remaining O&M expenses increase at a rate slightly above the Company's assumptions for GDP-PI. Using the Company's assumptions causes O&M

expenses to be approximately $100,000 higher each year than if the GDP-PI had been used to escalate those remaining O&M expenses, as intended by the Company. The staff corrected this.

b) Distribution rate change (T-2) – When it prepared its revenue model, the Company used an estimate of the July 1, 2007 distribution rates. However, the rates that actually went into effect were different than the Company's estimates. Using the actual rates increases the revenues by between $2.7 and $2.8 million each year.

c) Non-core revenue change (T-3) – The Company calculated winter and summer average rates for each class and then multiplied those rates by the load forecast to get a revenue forecast. In its model, the Company forecast core and non-core load separately and calculated average starting rates for the core customers and the core and non-core customers combined. It then applied the core rates to the core customers' loads and the combined core and non-core rates to the non-core load. Using the combined rates, rather than non-core only rates, understates the revenue approximately $100,000 per year, based on the Company's assumptions.

C. Base Case Adjustments - Summary

a) Capital structure (A-1) -- The Staff changed the Company's assumption for the cost of equity from 11.00% to 9.80%; the weighting for the cost of equity from 52.25% to 45.00%, and the weighting for the preferred stock rate from 1.56% to 2.00%.

b) Inflation assumptions – The Staff used the Blue Chip concensus forecast for the GDP-PI rates over time (A-2). In addition, the Staff applied a productivity offset factor of 1.75 to all expenses and capital items that are assumed to escalate at GDP-PI (A-3). (See below for an expanded discussion of inflation-related issues.)

c) O&M expenses (A-4) –The Staff changed the escalation factors for certain O&M expenses from the Company's discrete rates to GDP-PI (less the productivity factor). This modification was to the non-union portion of payroll expenses, medical, energy, MPUC assessment, storm reserve, and grid reliability O&M expenses. (See below for an expanded discussion of inflation-related issues.)

d) AMI reduction (A-5) – The Staff removed the expenses, savings and capital investment associated with AMI. Because of this modification, the Staff assumed that the part-time meter readers included in the adjusted test year would continue to be needed throughout the period.

e) Vegetation Management & Reliability (A-6) – The Staff removed the incremental external vegetation management expenses and capital costs and all of the Company's proposed incremental betterment expenses and capital costs. The remaining expenses were assumed to increase at productivity-factor adjusted GDP-PI.

f) Other Distribution Capital Additions (A-7) – The Staff assumed that the distribution capital additions escalate at the historic growth factor for these additions rather than the Company's assumed escalation factor.

g) SFAS-158 Adjustment (A-8) – The Staff recognized this asset in the beginning of the test year, rather than the end, and used a straight line depreciation. (See Revenue Requirement Appendix One)

h) Depreciation Adjustment (A-9) – The Staff assumed annual depreciation as discussed in the Bench Analysis. (See Revenue Requirement Appendix One)

i) SFAS-143 Adjustment (A-10) – The Staff reflected our proposal to flow back to ratepayers an adjustment associated with an over-collection of disposal costs associated with plant. (See Revenue Requirement Appendix One)

j) Merger Acquisition Premium Adjustment (A-11) -- Staff removed the merger acquisition premium recovery proposed by the Company.

k) Transportation Capital Additions (A-12) – Staff used the actual 2006 transportation capital costs for the test year and escalated the transportation capital costs at the historic distribution plant addition growth rate.

l) Advertising Expense (A-13) – Staff removed approximately $1.082M from the test year advertising expenses based on recoverable amounts allowed pursuant to Chapter 830.

m) Load Forecast (A-14) – Staff used its recommended load forecast for the residential classes. Staff also reflected the slightly different commercial sales descried in the sales forecast section. (Staff applied the commercial forecast to classes SGS through LGS-P. We note that

CMP's rate classes do not align precisely with commercial vs. industrial customers, and request CMP to provide commercial vs, industrial sales by rate class in its rebuttal filing.)

D. Expanded Description of Certain Base Case Assumptions

As noted above, most of the Staff Base Case assumptions are supported in other Sections of the Bench Analysis and simply summarized here. However, in the next section we provide an expanded discussion of two adjustments not addressed in other Sections.

a. Storm Reserve

The Staff supports the Company's normalization of storm costs for purposes of calculating revenue requirements in the rate effective year since storm costs can vary from year to year. However, for the reasons set forth below, the Staff recommends against the approval of the CMP reserve accounting for storm costs.

First, as a general matter, storms are a part of life in Maine and are a normal part of doing business as utilities in Maine. Although the Commission has granted accounting orders for storm costs in the past, such accounting orders have been only granted for storms which are truly extraordinary. *See Central Maine Power Company, re: Proposal for Accounting Order on Hurricane Bob, Docket No 92-019, Order (Nov. 10, 1992) and Central Maine Power Company, Deferral of Ice Storm of 1998 Service Restoration Costs, Docket No. 98-020, Order (Jan. 15, 1998).* CMP has suggested that it be provided flow-through accounting for any storm which exceeds interruption service to 10% of its customers. While such events may certainly not be an everyday occurrence, they clearly are not extraordinary.

Second, while CMP cannot control the weather, CMP does have control over its vegetation management program and its maintenance program which can strongly influence the extent of system damage and outages that result from a storm. Therefore, staff disputes that these events, especially at this level proposed by CMP, are entirely out of CMP's control.

Third, as discussed in other sections of this Bench Analysis, as result of CMP's tree-trimming practices during the past ARP, CMP's distribution system faces the threat of increased tree-related outages. CMP's ratepayers should not now bear the risk of increases in storm restoration costs for these past practices through a flow-through accounting mechanism.

Fourth, as can be seen from the proceedings involving the deferral and recovery of PCB-transformer costs, the question of what constitutes an allowable incremental cost, is subject to debate and would likely inject level controversy and complexity into the annual ARP proceeding, or as part of some other follow-up proceeding, which runs counter to the Commission's ARP goals and should be avoided.

Finally, deferral mechanisms such as the one proposed, run counter cost minimization goals of the ARP and in fact remove the cost minimization incentives of traditional cost of service regulation.

b. Inflation Adjustment

The Staff has used the projected rate of inflation as measured by the GDP-PI minus its recommended productivity offset of 1.75% to project O&M expenses (except for wages governed by contract) in calculating rate year revenue requirements and in modeling ARP results.

In CMP's filing, it applied discrete inflation rules for expenses, such as medical, which it expects to grow at rates higher than inflation, and the overall inflation rate for other expenses. In *Public Utilities Commission, Investigation of Central Maine Power Company's Revenue Requirements and Rate Design (Phase II),* Docket No. 97-580 (Jan. 19, 2000) Order at 27, the Commission stated:

> We believe that generalized overall cost trend rates are exactly the type of trend that is captured in the overall inflation factor. As OPA and the Advisory Staff have pointed out, CMP should not be allowed to take out specific costs that are growing at rates higher than inflation because it distorts the overall inflationary impact on the revenue requirement. As stated in the Bench Analysis:
>
> The attrition analysis considers costs that are increasing at rates that are both higher and lower than the rate of inflation. Therefore, even if one can point to specific costs that are increasing at a rate higher than inflation, it is important to consider that there are also costs that are increasing a [sic] rate less than inflation. Hence, removing cost elements to apply a separate cost escalation misstates the overall level of attrition.

In that case, the Commission also held that it was appropriate to incorporate a productivity offset to the projected inflation levels to calculate expense growth. *Public Utilities Commission, Investigation of Central Maine Power Company's Stranded Costs Transmission and Distribution Utility Revenue Requirements and Rate Design*, Docket No. 97-580, Order at 28 (March 19, 1999). In that case, the Commission utilized a 1% productivity offset which was consistent with the level used in CMP's ARP close to the 1.2% level found to be appropriate in Bangor Hydro-Electric's recently concluded case. In this case, Staff is recommending a 1.75%

offset to inflation for estimating expense growth, which is consistent with our ARP proposal recommendation.

IX. ALTERNATIVE RATE PLAN

A. Overall Recommendation

As discussed above, the Staff is recommending that the Commission not adopt an ARP at this time. As discussed in Sections IV and V, the Staff believes that there are too many uncertainties surrounding pending service quality performance, costs and timing of implementing both the AMI project and the Reliability Improvement Program, and the proposed sale of Energy East to Iberdrola, for the Commission to adopt a long term rate plan at this time. To the extent that the Commission concludes otherwise, and finds that an Alternative Rate Plan is warranted, after making the necessary starting point corrections to rates as discussed in section VI, the Staff proposes the following Staff Plan (ARP III) be adopted.

B. Overall Staff Plan Parameter

The overall rate change formula, or price index (PI) would be:

PI=inflation - productivity offset +/- mandated costs +/- earnings sharing +/- flow through items – service quality index (SQI) penalties.

The Staff proposes that ARP III have a term of five years, similar to ARP 95's term. The five year term is consistent with the modeling that has been done here, both by Staff and by CMP, and also provides for an earlier review by the Commission for how the ARP has performed.

Price changes would occur each July 1, with the first price change after the starting point adjustment to occur on July 1, 2009. The Company would submit a price change filing on March 15 of each year as it now does under ARP 2000.

C. Inflation Measure

The Staff agrees with the Company that the GDP-PI, as calculated by the Bureau of Economic Analysis (BEA), should continue to be used as the inflation measure in the price index formula. The Commission should use the most current calculation of the GDP-PI available at the time of the price change.

The Company in this case has proposed to include in the current year's price index any subsequent adjustment that the BEA makes to the GDP-PI used in prior years' price indices. Such adjustments would not only include changes made during the current ARP but would also include changes made for years covered by ARP 2000.

With regards to its proposal to make adjustments for revisions during ARP 2000, it appears that the Company is relitigating here, an issue which was deciding by the Commission during ARP 2000. *Central Maine Power Company, Annual Price Change Pursuant to the Alternative Rate Plan*, (Post-Merger), Docket No. 2004-167, Order on Contested Issues (June 23, 2004). In that case, as part of annual price change filing, the Company requested that the impacts of a revision by BEA to prior years' inflation estimates be reflected in the current price change. The ARP 2000 Plan was silent on the issue of BEA revisions to the GDP-PI. The Commission rejected CMP's argument that the revision component should be read into the ARP 2000 Stipulation. The Staff, therefore, recommends against CMP's proposal to incorporate

as part of this ARP revisions to ARP 2000 inflation adjustments as this issue has already been decided by the Commission.

While a closer call, the Staff also recommends against CMP's proposal to incorporate BEA's revisions to the inflation estimates made during prior years of the new ARP. As the Commission noted in its Docket No. 2004-167 decision, the question of whether to incorporate a revision provision as part of the inflation adjustment involves answering whether the benefits of using updated numbers outweighs the benefits of rate stability and administrative ease of leaving the estimates in place once they are made. The Staff believes that when the latter two factors are considered together, the balance favors not incorporating a revision provision as suggested by CMP.

First, as recognized by the Commission, the BEA is continuously revising its estimates of inflation and there is a question as to how you would draw a line as what changes should be reflected in future year's price changes. Second, again as noted by the Commission, the inflation calculation by the BEA is inherently an estimation and by taking a later calculation we are just replacing one estimate with another estimate which at some later point might be reestimated. Finally, we would note that the inflation revisions have gone both ways during the course of CMP's two ARPs and, thus, not including such a provision can be seen as symmetrical and does not inherently work towards either the advantage of CMP or its ratepayers.

D. Proposed Productivity Offset

Similar to ARP 95 and ARP 2000, the Staff's plan would include a productivity offset to the inflation adjustment. Such an offset recognizes expected productivity in excess of the levels embedded in the GDP-PI, based on both historical

information and on productivity improvements expected during the course of the ARP. For the reasons discussed in the following sections, Staff recommends that a productivity factor of 1.75% be adopted for ARP III.

1. Analysis of the Lowry Productivity Model

The CMP productivity factor (X-factor) proposal is supported by a study submitted by Dr. Mark N. Lowry, Managing Partner of Pacific Economics Group LLC. Dr. Lowry's study looks at the productivity and input price growth of fifteen New England and Upstate New York (Northeast) investor-owned utilities over the period 1993-2005. He finds that, over this time period, the average rate of productivity growth for the power distribution operations of these utilities is 1.57%, and that the average rate of input price growth is 3.36%. Dr. Lowry compares these rates of productivity growth and input price growth to estimated rates of productivity and input price growth for the U.S. economy. His estimate of economy-wide productivity growth is based on the Bureau of Labor Statistics multifactor productivity index for the private business sector, which grew 1.32% per year between 1993 and 2005. This leads to a productivity differential of 0.25% (1.57% - 1.32%). To estimate the rate of economy-wide input price growth, Dr. Lowry combines this rate of multifactor productivity growth with the rate of Gross Domestic Product Price Index (GDPPI) growth over that same period, and arrives at an estimate of 3.34% per year. This leads to an input price differential of -0.01% (3.34% - 3.36%, with both percentages rounded to the nearest hundredth of a percent). Finally, Dr. Lowry concludes that it would be reasonable to apply a stretch factor of 0.20% to the productivity factor. Combining the productivity differential, the input price

differential, and the stretch factor, Dr. Lowry concludes that a productivity factor of 0.44% would be reasonable.

Conceptually, basing the X-factor on a productivity differential, an input price differential, and a stretch factor is well grounded in economic theory and has been used previously in price cap plans. Basing the economy-wide rate of productivity growth on the BLS multifactor productivity measure, and basing the economy-wide rate of input price growth on the multifactor productivity measure and the GDPPI are also conceptually correct and have been used elsewhere. But there are a number of conceptual flaws in Dr. Lowry's productivity and input price analysis of the fifteen Northeast utilities that materially affect his estimated rates of productivity and input price growth, and hence his estimated X-factor. Furthermore, Dr. Lowry's recommended stretch factor understates the productivity benefits that customers should expect under the ARP.

2. <u>Analysis of Productivity and Input Price Differentials</u>

a. <u>Output Measurement</u>

The first flaw in the Lowry productivity analysis concerns his output measures. Dr. Lowry uses four measures of output: number of residential customers, number of non-residential customers, number of MWH delivered to residential customers, and number of MWH delivered to non-residential customers. Although standard productivity studies look at the relationship between actual levels of output and actual levels of input, Dr. Lowry's productivity analysis compares "weather-adjusted" measures of output to actual measures of input. Besides being an

unconventional method for measuring productivity, there are a number of problems with the method he uses to adjust output for weather.

Dr. Lowry uses an econometric model that relates annual MWHs to the number of cooling degree days. He then uses the parameter estimates from this regression to obtain the weather-adjusted volumes. Given the fact that he is trying to weather-adjust annual MWH's, it is problematic that no attempt was made to adjust for both the number of cooling degree days in summer and the number of heating degree days in winter. Furthermore, this approach ignores the impact of long term weather trends on electricity demand. In other words, the econometric model adjusts for both the short-term variations in weather that lead to short-run variations in MWHs and the long-term variations in weather that lead to long-run changes in MWHs.

Finally, the weather-adjustment process used actually increases, rather than decreases, the volatility of the output growth rates. The weather-adjusted total output index used by Dr. Lowry increases at an average annual rate of 1.30%. The largest increase for any one company in any one year was 11.92% while the largest decrease was -8.54%. The standard error of the annual growth rates is .043. Using the unadjusted output data, total output increases at an average annual rate of 1.48% (an increase of 0.18 percentage points). The largest increase for any one company in any one year is 8.28% while the largest decrease is -4.33%. The standard deviation of the annual growth rates is .020, which is less than half as large as the standard deviation using the weather-adjusted data.

Labor Price Measurement

The second flaw in the Lowry productivity study relates to his measurement of labor price. Conventional productivity studies maintain an identity between the cost of an input, that input's price, and that input's quantity. Specifically, the cost of the input should equal the price of that input multiplied by its quantity. In the case of labor, the Lowry model does not maintain this relationship. Maintaining this relationship between price, quantity, and cost is particularly important when one does not have a precise measure of either the price or the quantity. If one maintains the relationship that price times quantity equals cost, then approximation errors in the quantity index (which will affect the estimated productivity differential) will have an offsetting approximation error in the price index (which will affect the input price differential in an offsetting way), leading to no net effect on the X-factor.

Dr. Lowry's estimate of labor cost is based on wages and salaries booked to the distribution, customer accounts, customer service and information, and sales functions, plus a fraction of wages and salaries booked to the administration and general function, plus a fraction of pensions and benefits. In order to generate a labor quantity index, Dr. Lowry divides the wages and salaries portion of his labor cost estimate by a wage and salary index he constructs from Bureau of Labor Statistics Employee Cost Indexes. This wage and salary index is based on general wage and salary trends in the national utility industry (electricity, gas, water and sewer) and wage and salary trends for all industries in the BLS Northeast region.[22] One should note that this price index is not based on information specific to the companies in question, but is inferred based on national wage and salary trends in the utility industry

[22] The Bureau of Labor Statistics defines the Northeast region to include New England plus New York, New Jersey, and Pennsylvania.

and wage and salary trends for all industries in the Northeast. One should also note that there are differences in the definition of wages and salaries reported in the FERC Form 1 report and the definition used to construct the Employment Cost Index. Specifically, the Employment Cost Index for wages and salaries does not include any wage premiums (e.g. overtime, night differentials, and bonuses) nor does it include any paid leave (e.g. vacation, sick leave). Rather, these payments are considered benefits.

Even if his approach represents the best possible approximation to the wage and salary trends for the companies he is analyzing, it is subject to approximation error. Dr. Lowry could have preserved the relationship between labor cost, labor price, and labor quantity by basing his labor price on the ratio of his estimate of labor cost to his estimate of labor quantity, but he chose not to do that. Instead he bases his labor price index on a set of Employee Cost Indexes for total compensation (i.e. wages and salaries plus benefits). As with the Employee Cost Indexes for wages and salaries, these indexes represent general total compensation trends in the national utility industry and total compensation trends for all industries in the BLS Northeast region. Our analysis shows that Dr. Lowry's labor price measure increases at an average annual rate of 3.69% while the labor price measure consistent with Dr. Lowry's labor cost and labor quantity increases at an average annual rate of 2.83%.

Dr. Lowry indicated that he did not use the latter price measure because there were large year-to-year variations in the amount of pensions booked in any one year.[23] But if this is a significant problem, the solution would be to

[23] Docket 2007-215, Technical Conference, July 19, 2007, pp. 17.

make explicit adjustments to the booked employee pensions and benefits, not to ignore those booked expenses. The average rate of labor price growth that is obtained using the latter approach is based on company specific data for fifteen companies over twelve years. We see no reason to believe that averaging this number of observations to obtain the trend rate of labor price growth is any more problematic than the use of this type of averaging to derive the trend rates of input and output growth.

b. Results of Correcting Output and Labor Price Measures

When we correct the output measure and the labor price measure, we find that the rate of power distribution productivity growth increases at an average annual rate of 1.75% and the rate of input price growth increases at an average annual rate of 3.22%. The resulting productivity differential is 0.43% and the resulting input price differential is 0.12%.

c. Administrative and General Expenses

The third flaw in the Lowry productivity analysis is related to his treatment of administrative and general expenses. Dr. Lowry estimates productivity and input price growth for power distribution, rather than estimating the rate of total factor productivity growth for the integrated operations of the companies in his study, and he must make an allocation of joint and common costs. Dr. Lowry allocates administrative and general expense to electricity distribution based on the share of “net operating and maintenance expense” reported in distribution, customer accounts, customer service and information, and sales relative to the amounts reported in

production and transmission.[24] As an example, in 1996, Central Maine Power net O&M production costs were $29.8 million, transmission net O&M expenses were $12.0 million, and power distribution net O&M expenses were $99.0 million. According to the Lowry allocation formula, 21% of administrative and general expense is allocated to production operations, 9% to transmission operations, and 70% to electricity distribution operations.

From a productivity measurement perspective, the allocation of joint and common costs to the different lines of a company's business has no methodological basis and hence is hence arbitrary. Different allocation methods can produce different productivity results. When an industry goes through significant structural changes, the differences in productivity results can be significant. In the Lowry study, a number of the companies in his analysis divested themselves of production operations over the study period. According to the Lowry allocation methodology, these companies should have reduced their administrative and general expenses proportionally, or their measured power distribution productivity would decrease. For example, Central Maine Power's divestiture of production would require a reduction of administrative and general expenses by 21% for power distribution productivity not to have been negatively impacted.

The problem that joint and common costs presents for the measurement of productivity is not specific to the electric utility industry, as it has been also significant in the telecommunications industry. Interstate telecommunications services and intrastate telecommunications services have been regulated under

[24] Net operating and maintenance expense excludes fuel costs, some purchased power costs, transmission costs associated with wheeling, and franchise fees.

separate jurisdictions. They share joint and common inputs between themselves and with unregulated services. To avoid the problem of arbitrarily allocating joint and common costs to the different services, the approach taken to develop price cap X-factors has generally relied on estimating total factor productivity for the integrated operations of the telecommunications companies rather than partial productivity studies of interstate and intrastate services. Methodologies have furthermore been developed that can be used to develop different X-factors for different bundles of services.[25]

To show the sensitivity of the productivity results to the allocation rule employed, we consider a scenario where no administrative and general expenses are allocated to production. Under this scenario we find that the average annual rate of power distribution productivity growth is 2.35% and the productivity differential is 1.03%. Because the allocation of administrative and general expenses also affects the weights assigned to the prices of capital, labor, and materials, we find that the rate of power distribution input price growth changes to 2.96%, and the input price differential is 0.38%. This result indicates that there is a range of plausible productivity and input price growth rates that come out of the Lowry study.

Although a wide range of productivity results can be supported by the partial productivity framework presented by Dr. Lowry, we decided to review Docket 97-580, to see if it might provide some guidance as to what allocation formula might be reasonable in this price cap docket. Docket 97-580 addressed the transmission and distribution revenue requirement at the time of the Central Maine Power's restructuring. In that Docket, both the Company and the Commission were

[25] Jeffrey I. Bernstein and David E.M. Sappington, "Setting the X Factor in Price-Cap Regulation Plans," Journal of Regulatory Economics, 16 (1999), pp. 5-25.

attempting to determine what fraction of total administrative and general expenses would stay with the company if production operations were divested. Central Maine Power argued that of the $47.617 million in company test year administrative and general expenses, $2.099 million were directly assigned to production operations, and an additional $2.370 million could be eliminated due to eliminating production operations. The Commission reviewed this and other evidence, and in its 1999 Phase I Order, the Commission ruled that an additional $2.597 million of administrative and general expenses should be taken out of the transmission and distribution revenue requirement, to better reflect the administrative and general expenses once the production operations were eliminated. [26] The Commission reviewed the transmission and distribution revenue requirement a second time in its Phase 2 Order and made further adjustments that added back $1.710 million of test year administrative and general expenses to transmission and distribution.[27] This means that of the $47.617 million company administrative and general expenses, $42.261 million, or 89%, were assigned to transmission and distribution operations and $5.356 million, or 11%, to production operations. In other words, the decision allocates a significantly smaller fraction of administrative and general expenses to production than does the Lowry allocation formula.

The Lowry allocation formula gives equal weight to one dollar of production net O&M expenses and one dollar of transmission and distribution net O&M expenses. One can modify this formula to give each production dollar less

[26] Docket 97-580, March 19, 1999 Order, pp. 2-13.

[27] Docket 97-580, January 19, 2000 Order, pp. 6-9.

weight than each transmission and distribution dollar. If we give each production dollar a weight of .47 relative to each transmission and distribution dollar, we then assign 11% of 1996 administrative and general expenses to production and 89% to transmission and distribution, i.e. the cost separation that was determined in 97-580. Lacking similar information on cost separations for the other companies in the study, we decided to consider a scenario where a weight of .47 is assigned to each production dollar when distributing administrative and general expenses for all of the companies in the sample. We find that this weighting factor leads to a productivity growth rate of 1.97% per year and an input price growth rate of 3.12% per year (including the output and labor price corrections). This leads to a productivity differential of 0.65% and an input price differential of 0.22%.

d. Capital Input

There is one additional aspect of the Lowry methodology that warrants discussion, namely the measurement of capital input. In this study, Dr. Lowry employs a new approach to capital measurement,[28] one that differs from the approach he has taken in previous studies.[29] It is important to review the principles underlying both approaches to measuring capital input and to determine the sensitivity of his results to these alternative approaches.

[28] Lowry indicated that he is also using this method in an Ontario regulatory proceeding, but that docket has not yet been completed. Except for this docket, he has not previously used this approach for measuring capital input. (Docket 2007-215, Technical Conference, July 19, 2007, pp. 19-20)

[29] See Lowry's 2006 testimony in California and Vermont, Attachments 1 and 2 to ODR-01-54 response.

As Dr. Lowry points out, the measurement of capital input is conceptually the most difficult part of productivity measurement. In the case of power distribution it is also one of the most important, as capital input accounts for approximately half of total input. The conceptual difficulty arises from two factors. First, in order to obtain a measure of total capital input quantity, one must determine the appropriate weights for the different vintages of assets. There have generally been three approaches taken to weighting different vintages of assets. The first approach is to assume that an asset maintains a constant level of productive efficiency over its lifetime. This assumption, generally known as the 'one hoss shay' model of capital, is implicitly employed when the measure of capital input is based on gross stock measures. The second approach is to assume that an asset's level of productive efficiency declines at a linear rate as it ages. This assumption is implicitly employed when the measure of capital input is based on net stock measures. The third approach is to assume that an asset's level of productive efficiency declines at a constant rate as it ages. This is known as the geometric model of capital.[30] There has been substantial body of economic literature devoted to determining which of these three patterns is most appropriate for capital measurement. These studies have been nicely summarized in two papers by Hulten and Wykoff.[31] Most of the empirical evidence supports the geometric assumption over the 'one-hoss shay' or straight line pattern.

[30] The term "straight line" is sometimes applied to the linear model, while the term "declining balance" is sometimes applied to the geometric model.

[31] C.R. Hulten, "The Measurement of Capital," in E.R. Berndt and J.E. Triplett, eds., Fifty Years of Economic Measurement, Chicago: University of Chicago Press (1990), pp. 119-52; C.R. Hulten and F.C. Wykoff, "Issues in the Measurement of Economic Depreciation: Introductory Remarks," Economic Inquiry, 34 (1996), pp. 10-23.

The second factor that makes the measurement of capital conceptually difficult is that one does not directly observe the price of using capital input in a given year. Capital inputs are generally purchased for use over a number of years; hence the observed purchase prices of capital assets are “investment” prices and not “utilization” prices. This situation contrasts to observed prices for labor, where the payments made are directly related to the work being performed during the year. (There are limited rental markets for some types of capital. In those situations, the rental prices represent prices for utilizing those capital assets.) Because utilization prices are not observed, they must be inferred. Most productivity studies rely on a model of competitive market prices for capital goods, which can be used to derive capital utilization prices, also called implicit rental prices, from the investment prices of assets. This approach to measuring the price of capital input differs from conventional “cost of service” methods. In cost of service studies, the price associated with capital is developed from the original cost of the asset, market interest rates, and straight line depreciation rates. Both the implicit rental price model and the cost of service model recover the investment cost of an asset over its lifetime, but the timing of cost recovery differs. In the Appendix, we show mathematical representations of both approaches.

In the study he conducted for Central Maine Power (the current study), Dr. Lowry assumes that an asset’s efficiency declines linearly as it ages and he uses cost of service principles to measure the price of capital. In the previous studies cited above, Dr. Lowry uses the geometric model and implicit rental prices.

To determine the sensitivity of his results to his capital measurement methodology, we calculated capital price and quantity measures based on the

geometric and implicit rental price models. We apply these methods to the data that underlie Dr. Lowry's capital input calculations. Details to the computations are found in the Appendix. If we use this alternative methodology to measure capital input, along with the corrections to output and labor price and assigning a weight of .47 to production net O&M expenses, we find that productivity growth for the fifteen Northeast utilities increased at an average annual rate of 1.88% and the input price increased at an average annual rate of 2.36%. While this alternative capital input approach produces a slightly lower productivity differential of 0.56%, it produces a substantially higher input price differential of 0.98%.

3. Summary

The following table shows the productivity differential and input price differential presented by Dr. Lowry and the differentials under the alternative calculations we have considered. The range of corrected X-factors runs from 0.54% to 1.54%, with the mid-point of this range about 1.0%. Based on this table, we believe that Dr. Lowry's data support an X-factor of 1.0% before application of a stretch factor.

Calculation of Productivity and Input Price Differentials Under Different Assumptions			
Assumptions	Productivity Differential	Input Price Differential	Productivity Factor Before Stretch
Lowry Model	0.25%	-0.01%	0.24%
Adjust Output and Labor Price	0.43%	0.12%	0.54%
Adjust Output and Labor Price, No A&G Allocated to Production Operations	1.03%	0.38%	1.40%
Adjust Output and Labor Price, Weight Production O&M by .47 when Allocating A&G	0.65%	0.22%	0.87%
Adjust Output and Labor Price, Weight Production O&M by .47 when Allocating A&G, Geometric Capital	0.56%	0.98%	1.54%

4. Stretch Factor

The principle behind applying a stretch factor (sometimes known as a consumer productivity dividend) to a price cap formula is that price caps should generate additional productivity gains through greater incentives and that customers should benefit from those gains. The Federal Communications Commission had considerable discussion concerning consumer productivity dividends when establishing a price cap for AT&T long distance services. The Commission explained that the consumer productivity dividend “ensures that consumers are the first beneficiaries of added efficiency under price caps … Only after AT&T achieves this degree of efficiency

will it be in a position to reap rewards."[32] The Canadian Radio-television and Telecommunications Commission also has adopted the stretch factor in developing price caps, and in its Glossary of Telecommunications Terms define the stretch factor as "an adjustment factor of the additional efficiency the companies are expected to achieve, as a result of the streamlining of regulation through price caps and the incentives incorporated with pricing flexibility, in the form of savings for ratepayers."[33] Bernstein and Sappington provide an extensive discussion on the principles that underlie construction of a price cap index. In their discussions of the consumer productivity dividend, they state that "In principle, the CPD (i.e., Consumer Productivity Dividend) should reflect the best estimate of the increase in the productivity growth rate in the regulated sector that will be induced by the new enhanced incentives in the regulated industry."[34]

Generally, price cap stretch factors have ranged from 0.5 percentage points to 1.0 percentage points, although larger stretch factors have been applied in some instances where the regulated firm was viewed as having significant inefficiencies. Dr. Lowry proposes a substantially lower stretch factor of 0.20 percent. This is based on three arguments that he makes. First, he believes the seven year price cap plan that will regulate Central Maine Power prices should generate an additional productivity growth of 0.4 percentage points per year, compared to the rate of productivity growth observed for the 15 Northeast utilities. Second, Dr. Lowry believes

[32] Report and Order and Second Further Notice of Proposed Rulemaking, CC Docket 87-313, March 16, 1989, Para 248.

[33] http://www.crtc.gc.ca/eng/INFO_SHT/t1010.htm

[34] Bernstein and Sappington, op. cit., p. 19.

that the gains from alternative regulation should be shared equally between the company and the consumers. Third, Dr. Lowry states that the productive efficiency of Central Maine Power is roughly similar to the 15 Northeast utilities, so there is no need to include a component to the stretch factor that reflects company inefficiencies.

In support of his conclusion that the alternative regulation plan should generate additional productivity gains of 0.4% per year, Dr. Lowry relies on a simulation model that relates the costs of efficiency improvement programs (including the nuisance and regulatory costs), the regulatory structure, and the profitability of undertaking those programs. There is no empirical information that is used to calibrate this model, and Dr. Lowry concedes that it would be difficult, if not impossible, to base some of the elements of his model on empirical information. Dr. Lowry also does not provide any empirical evidence on how incentive regulation plans have generated additional productivity gains in other jurisdictions. Because of these deficiencies, we do not believe that the model results should be given any weight when determining the X-factor.

Even though Dr. Lowry believes that the price cap structure will generate an additional 0.4% growth in productivity, he proposes that only half of that amount be passed onto consumers in the form of lower prices. This position contrasts sharply with the framework established by Bernstein and Sappington, which includes all of the expected productivity gains in the stretch factor. His language of splitting the gains 50/50 between company and consumers is also not supported by the language adopted by the Federal Communications Commission or the Canadian Radio-television and Telecommunications Commission, where the first benefits from the price cap are

passed on to consumers. We therefore do not find Dr. Lowry's argument convincing and feel that all of the expected productivity benefits generated by the price cap structure should be passed on to customers in the form of lower prices. This still allows the company to reap all of the benefits from productivity gains exceeding this benchmark.

Finally, to support his claim that Central Maine Power's level of efficiency is not materially different than that of the 15 Northeast utilities, Dr. Lowry relies on three econometric benchmarking studies. The first of these studies was published in the Energy Journal in 2005.[35] The other two were submitted in rate cases in California and Vermont in 2006.[36]

In the Table 6 of the Energy Journal article, Dr. Lowry shows how his econometric model can be used to rank power distribution companies and how that ranking can be used to develop price cap stretch factors for utilities under price cap plans. The table shows performance of the companies in his analysis, with the companies identified by a utility ID number. Dr. Lowry indicated that the utility ID number used in that table is the same ID number that he uses in his study for Central Maine Power.[37] This would mean that Central Maine Power's performance is represented by the firm with the ID "23." Central Maine Power has a score of -.036 in

[35] Mark Newton Lowry, Lullit Getachew, and David Hovde, "Econometric Benchmarking of Cost Performance: The Case of U.S. Power Distributors," The Energy Journal, 26 (2005), pp. 75-92.

[36] "Prepared Direct Testimony of Mark Newton Lowry, Ph.D., on Behalf of the San Diego Gas and Electric Company, Before the Public Utilities Commission of the State of California, December 2006" and "The Cost Performance of CVPS in Power Distribution, May 18, 2006," Attachments 1 and 2 to ODR-01-54 response.

[37] Docket 2007-215, Technical Conference, July 19, 2007, p.27.

that table, which would be interpreted as saying that the actual cost of Central Maine Power is 3.6% below the industry average after the impacts of relevant business conditions are considered. Dr. Lowry observes that the score is a statistical estimate and computes a p-value for that score. He is unable to reject the hypothesis that Central Maine Power's cost performance is the same as the industry average.

In Table 6, Dr. Lowry groups the utilities into "significantly superior performers," "average performers," and significantly inferior performers." Central Maine Power falls into the second group. The estimated score for the top ranking performer is -.374, which is interpreted as that company having a cost level 37.4% below industry average, after the correction of network and environmental factors. The average score for the companies in this first group is -.252, which can be interpreted as indicating that on average, this group of significantly superior performers has cost level that is 25.2% below the industry average. These results indicate that Central Maine Power cost performance is considerably below best practice in the industry. (As Dr. Lowry notes, the scores are statistical estimates, and the actual performance of these companies may be somewhat higher or lower.)

The studies presented in the California and Vermont rate cases are somewhat different than the published study, in that they consider slightly different sets of business conditions. In the California study, Dr. Lowry finds that Central Maine Power's cost performance was 1.7% above the industry average, after correcting for network and environmental factors, and in the Vermont study he finds that Central Maine Power's cost performance was 5% above industry average. In both studies he finds that he cannot reject the hypothesis that Central Maine Power's cost performance

is the same as the industry average. Information on other firms in those studies is not available, but there is nothing in those studies that undermine the conclusions drawn from the Energy Journal paper. One should also note that most of power distribution companies in the United States do not operate under price cap plans, and therefore the average cost performance reported in these studies does not incorporate the cost efficiencies that one would expect under price caps.

5. Conclusion

After reviewing the evidence on stretch factors in the Lowry study, we find nothing that would invalidate selecting a stretch factor somewhere between 0.5% and 1.0%. If we choose the mid-point of this range, as we did with the range of X-factors before the application of a stretch factor, this would lead to a stretch factor of 0.75% and a final X-factor of 1.75%.

E. Mandated Costs

Consistent with the provisions of ARP 2000 the Company would be eligible to receive, or would be required to pass through, costs which qualify as mandated costs. To be eligible for recovery each mandated cost item must exceed $150,000. Eligible mandated cost items will be aggregated and the aggregate which exceeds $3 million will be included in rates.

Mandated costs are changes in costs beyond the Company's control which are the result of either: 1) force *majeure*; or 2) changes in federal or state legislation, regulation or accounting requirements. As discussed above, the Staff opposes the Company's proposal to include all storms which meet the 10% SQI exemption level as part of a reserve accounting mechanism. For similar reasons, the

Staff would not include such occurrences as force *majeure* extraordinary weather events eligible for mandated cost treatment. Instead, the Staff proposes a standard similar to that agreed to by Bangor Hydro during its current ARP. Thus, to be eligible as an extraordinary weather event and thus qualify as a mandated cost:

1. The event must be classified on the website of the National Climatic Data Center (a division of NOAA) or its successor entity (on a succeeding website) to be an “extreme weather event”:

2. The event must directly result in CMP incurring more than $400,000 of storm restoration costs defined as those costs prudently incurred and necessary to restore service to customers affected by the extreme weather event; and

3. Over 3 successive calendar days the event must result in disruption of service to more than

   a. 20% of CMP customers; or

   b. 50% of CMP customers within one of the eleven CMP operating divisions.

Any weather event that satisfies the criteria of paragraphs (2) and (3) above and is not classified on the NOAA website as an “extreme weather event” shall nevertheless qualify as an “extraordinary weather event” if CMP can demonstrate that the event’s failure to be classified as an “extreme weather event” is due to the oversight or neglect of the classifying agency and not to deliberate exclusion.

F. Earnings Sharing

Under ARP 95 earnings outside of a +/- 350 basis point dead zone which surrounded the target ROE (return on equity) were shared between ratepayers and

shareholders on a 50/50 basis. In ARP 2000, the Staff in its Bench Analysis proposed an asymmetrical bandwidth which did not include a top end band for sharing but did include bottom end sharing where the Company's ROE went below 5.2%. The Staff's asymmetrical approach proved somewhat controversial.[38] In this case the Staff is recommending the Commission go back the +/-350 basis point bandwidth utilized in the first ARP.The +/-350 basis bandwidth should be sufficiently wide as to avoid rate type hearings on a sustained basis and provide incentives for the Company to improve productivity. The bandwidth also provides a back stop and a means of providing rate mitigation for assumptions going into plan which proved to be either overly optimistic or pessimistic, or for unforeseen events which might otherwise not be accounted for in the plan.

The earnings sharing mechanism also provides a vehicle of rewarding the Company for superior reliability performance without penalizing ratepayers through higher rates. As discussed in the reliability section, the Company would be eligible for expanded upper end earnings sharing if the Company were able to achieve above average reliability performance. The expansion of the upper end sharing, as suggested in the Williams' Report, provides a means of rewarding the Company for above average or superior performance.

Finally, although we are not proposing "off-ramp" ARP proposal, if a longer-term ARP is adopted, the Commission should consider an "off-ramp" mechanism to protect against sustained over or under earning conditions.

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[38] See *Docket No. 99-666, supra.* At 18, Dissent of Commissioner Diamond and the Law Court Appeal of the IECG, *Industrial Energy Consumer Group v. Public Utilities Commission,* 773 A.2d. 1038 (Me. 2001).

G. Flow-through Items

Environmental clean-up costs subject to the reserve accounting treatment, discussed above, would be eligible for flow-through treatment. In addition, revenues and costs associated with DSM and the Low-Income Assistance Program would continue to be reconciled and subject to flow-through as they are under the current ARP. Finally, capital gains on utility property which had been included in rate base would also be subject to flow-through if the gains in any one year exceeded $150,000.

The Staff is not proposing as part of its 5-year plan that any expiring amortizations be treated as a flow-through item as had been the case in ARP 2000. If the Commission adopts plan longer than 5 years, however, the Staff would recommend that the FAS 106 regulatory asset amortization, which expires in 2012, be subject to flow-through treatment and that both the expense and rate base (based on rate-effective year level) be removed to coincide with its expiration.

H. Staff Recommended Service Quality Index

1. Overview

CMP's service quality was measured during ARP 2000 through a Service Quality Index (SQI). The SQI was made up of the following eight indicators: Customer Average Interruption Duration Index (CAIDI); System Average Interruption Frequency Index (SAIFI); Percent of Business Calls Answered; Percent of Outage Calls Answered; New Service Installations; Service Order Timeliness; MPUC Complaint Ratio; and Market Responsiveness. As is clearly evident from our examination of CMP's O&M and investment during ARP 2000, these metrics were not adequate to ensure reasonable customer service.

In its filing, CMP proposes to continue with these eight metrics and recommends a new metric to measure estimated meter reads. We disagree with certain aspects of CMP's recommended SQI and thus recommend it be modified. We find that two of the metrics recommended by CMP and included in the ARP 2000 SQI, the "percent of outage calls answered" and the "market responsiveness" metrics, are no longer useful and should be eliminated. We also find that other metrics should be added to ensure that service quality areas important to customers are covered in the SQI. In particular, the Williams report makes several recommendations for improving CMP's reliability performance that we believe should be addressed in the ARP III SQI. In addition, CMP's performance for several metrics over the past three years is significantly better than the corresponding baselines recommended by CMP. For these metrics, we recommend that baselines be adjusted to reflect the better historical performance. We discuss these recommendations in depth below.

2. <u>Staff Recommended SQI</u>

The following table depicts the ARP 2000 SQI metrics and baselines, CMP's recommended ARP III metrics and baselines, and staff's recommended ARP III metrics and baselines. Each metric is discussed in depth below.

Indicator	ARP 2000 Baseline	CMP Proposed Baseline	Staff Proposed Baseline
CAIDI	2.32	2.15*	2.18
SAIFI	2.10	1.70**	2.10***
MPUC Complaint Ratio	1.17	1.00	.93
Percent of Business Calls Answered	80%	80%	82%
Percent of Outage Calls Answered	80%	80%	Eliminate
New Service Installation	93%	95%	TBD
Call Center Service Quality	84%	85%	88%
Market Responsiveness	100%	100%	Eliminate
Worst Performing Circuit (SAIFI)	N/A	N/A	6.30
Estimated Bills	N/A	TBD	TBD

* CMP proposed a baseline of 2.32 for 2008 and 2009, 2.29 for 2010, 2.25 for 2011, 2.22 for 2012, 2.18 for 2013, and 2.15 for 2014.
**CMP proposed a baseline of 2.10 for 2008 and 2009, 2.02 for 2010, 1.94 for 2011, 1.86 for 2012, 1.78 for 2013, and 1.70 for 2014.
*** Staff proposes a baseline of 2.10 for 2008, 2.0 for 2009, 1.95 for 2010, 1.90 for 2011, and 1.85 for 2012.

a. Customer Average Interruption Index (CAIDI)

CAIDI represents the average time required to restore service to the average customer per sustained interruption.[39] The CAIDI formula is:

$$\text{CAIDI} = \frac{\Sigma\ \text{Customer interruptions durations}}{\text{Total number of customers interrupted}}$$

[39] CAIDI is defined and calculated in accordance with IEEE Std. 1366-1998, or a more recent version, if any.

CAIDI is a good indicator of the quality of a utility's response to outages. The higher the CAIDI number, the longer it takes on average for the utility to restore service customer experiencing an outage.

Staff recommends that the baseline for CAIDI be 2.18 hours per year. This baseline reflects CMP's poorest annual performance over the past three years (2005). CMP recommended a baseline of a baseline of 2.32 for 2008 and 2009, 2.29 for 2010, 2.25 for 2011, 2.22 for 2012, 2.18 for 2013, and 2.15 for 2014. Because CMP's performance during ARP 2000 has been significantly better than 2.32, we recommend the baseline be adjusted to reflect the poorest performance experienced during the past three years.

b. System Average Interruption Frequency Index (SAIFI)

SAIFI provides information regarding the average frequency of sustained interruptions[40] per customer over a predefined area.[41] The SAIFI formula is:

$$\text{SAIFI} = \frac{\text{Total number of customer interruptions}}{\text{Total number of customers served}}$$

SAIFI is a good indicator of the condition of a utility's plant, as well as the quality of the utility's tree trimming and preventive maintenance activities. The higher the SAIFI number, the more sustained outages the average customer

[40] Pursuant to the Institute of Electrical and Electronics Engineers, Inc. Standards Board (IEEE) standard 1366—1998, a "sustained interruption" is "any interruption not classified as a momentary event. Any interruption longer than 5 minutes."

[41] SAIFI is defined and calculated in accordance with IEEE Std. 1366-1998, or a more recent version, if any.

experiences. If a utility's plant is antiquated or has not been properly maintained, the distribution system may be more susceptible to outages caused by storm damage and equipment failure. Also, if adequate tree trimming has not taken place, the transmission and distribution system is more susceptible to outages caused by tree limbs contacting the utility's equipment.

Staff recommends a baseline of 2.10 for 2008, 2.0 for 2009, 1.95 for 2010, 1.90 for 2011, and 1.85 for 2012. In its report, Williams recommends that the Commission tighten CMP's SAIFI target (baseline) such that its performance improves into the third quartile of national reliability performance within the next three years.[42] To move into the third quartile of performance, CMP's performance would need to be 1.75 interruptions per year. While our recommended baselines do not specifically meet this objective, we believe that they represent an improvement in service quality and will move the company in the right direction. We encourage CMP, however, to do its best to reach the 1.75 needed to meet the Williams recommendation.

c. <u>Worst Performing Circuits</u>

As noted earlier, the metrics used in ARP 2000 were not adequate incentives to ensure reasonable service quality. A major flaw of the ARP 2000 metrics was their lack of granularity in terms of measuring performance in particular service areas or circuits. Thus, Staff recommends a new metric be added to CMP's SQI to measure its performance at the circuit level. In particular this metric will

[42] The Institute of Electrical and Electronic Engineers (IEEE) conducts an annual reliability survey of national electric utilities. The purpose of the survey is to provide utilities and regulators with a common set of measurements, terms, and definitions intended to enable discussions and comparisons of electrical reliability performance from a common basis. The IEEE's 2004 survey shows CMP in the fourth quartile compared to other electric utilities nationally.

focus on individual circuits with poor performance, regardless of how many customers are served by the circuit. The metric will use SAIFI by circuit data to identify CMP's worst performing circuits and is intended to ensure that proper attention is provided to circuits with a low number of customers. We recommend a baseline is 6.3 interruptions per year, which is three times the overall company's 2008 SAIFI baseline of 2.1.

This recommendation is consistent with the William's Report recommendation that the company's overall worst performing circuits, as well as the Company's poor performing circuits as identified using the circuit's impact on the Company-wide SAIFI result, be considered in the SQI.[43] In its report, Williams stated that its analysis of worst performing circuits for the period of 2001 through 2005 found a surprisingly high number of circuits that fell into the category of ten worst performers for more than one year and noted that the majority of these circuits are located in less densely populated, more rural service areas. Williams further noted that "good utility practice is to assure that worst performing circuits do not appear more than twice in annual reporting and certainly not in consecutive years."

In light of the William's recommendation, we recommend that if SAIFI for any circuit exceeds the baseline of 6.3 for two consecutive years, a penalty would apply for each consecutive year. For example, if the individual SAIFI for a circuit exceeds 6.3 for three consecutive years, a penalty will be assessed for years

[43] Traditionally, per circuit SAIFI performance was used either by itself or in conjunction with other reliability measures to identify poor performing circuits. Beginning in 2003, CMP stopped using SAIFI performance by circuit to identify poor performing circuits and began using each circuit's impact on the company-wide SAIFI performance to identify poor performing circuits. This method places much more emphasis on circuits with a high number of customers than circuits with a low number of customers.

two and three. No penalty will be assessed for a circuit whose individual SAIFI exceeds the baseline of 6.3 for only one year.

d. MPUC Complaint Ratio

The MPUC complaint ratio is the annual number of complaints filed with the CAD against a utility per 1,000 customers. We agree with CMP's proposal for this metric, with the exception that we recommend a baseline of .93, as opposed to 1.00. The slightly lower baseline (better performance) represents the company's poorest performance within the past three years (2005).

e. Percent of Business Calls Answered

The "percent of business calls answered" metric represents the percentage of calls received by CMP's customer service line that are answered by a live customer representative or the company's Interactive Voice Response System (IVR). We agree with CMP's proposal for this metric, with the exception that we recommend a baseline of 82%, as opposed to 80%. The slightly higher baseline (better performance) represents the company's poorest performance within the past three years (2005 and 2006).

f. Percent of Outage Calls Answered

This metric measures CMP's performance in answering its outage reporting line. Because CMP uses an automated system to record customer outage reports, it has achieved a 100% answer rate for outage calls throughout the ARP 2000 period. In light of this, we do not believe a metric to measure the percent of outage calls answered is necessary and thus recommend it be eliminated. In conjunction with this recommendation, we also recommend that CMP be prohibited from

altering its outage answering system without first receiving permission from the Commission.

g. New Service Installations

Under ARP 2000, this metric measured the percentage of new service installations installed and energized by the date promised by CMP. CMP proposes to continue this metric under ARP III. Staff recommends that this metric be modified to measure the percentage of service orders fulfilled within a designated period (referred to as the "goal" dates). Under the existing metric, there is no limit regarding the amount of time CMP can take to install service, as long as it installs the service by whatever date it promises the customer. We find this problematic. We believe that acceptable time periods for various types of service orders should be established, similar to BHE's "Service Order Timeliness" metric (see attached "Service Order Timelines Goal Dates" document for BHE). We recommend that CMP, in conjunction with staff, develop a list of all service order types, similar to BHE's, and establish reasonable goal dates for each service type. CMP's performance will be calculated by dividing the number of service orders fulfilled by the goal date by the total number of service orders received. We further recommend that the 95% baseline recommended by CMP for its new service installation metric be applied to the modified metric.

h. Call Center Service Quality

This metric measures customer satisfaction with responses provided by CMP's customer service representatives to calls received over CMP's business line. We agree with CMP's proposal for this metric, with the exception that we recommend a baseline of 88%, as opposed to 85%. The slightly higher baseline (better

performance) represents the company's poorest performance within the past three years (2006).

i. Market Responsiveness

This metric tracked the percentage of properly completed and transmitted enrollment requests received from competitive electricity providers that were processed within the timeframes specified in Chapter 322 of the Commission's rules. This metric was included in ARP 2000 as a means to ensure that the Company provided the appropriate level of attention to processing enrollment requests, even though it was required by rule. Because CMP has achieved this metric all five years under ARP 2000 and it is addressed in a Commission rule, we do not believe it is a necessary metric and recommend it be eliminated.

j. Estimated Bills

CMP is in the process of developing a baseline for this metric. Staff recommends that this metric be adopted and that CMP work with staff and the parties to ascertain the appropriate baseline.

3. Storm Exemption Process

CMP recommends that the exemption process utilized under ARP 2000 be continued under ARP III. Under the current exemption methodology, anytime 10% or more of the customers in CMP's service territory experience a service interruption, all outages in CMP's service territory associated with that event are excluded from the calculation of the metric. Staff recommends that the Commission adopt the IEEE Beta Method (Beta Method) for excluding "extraordinary events" from the service quality metrics.

The Beta Method identifies specific days (referred to Major Event Days or "MED"s) to be removed from the reliability index calculations. This method uses historical SAIDI results to establish a "major day threshold value," T_{med}, for SAIDI. The major day threshold value is calculated at the end of each reporting period (typically one year) for use during the next reporting period. Any day during the reporting period with a daily SAIDI greater than the T_{med} is classified as a "major event day" and removed from the index calculation. "Major event days" are removed from all reliability index calculations, even though it is based on SAIDI. The SAIDI index is used because its results are consistent between utilities of different sizes and because SAIDI is a good indicator of overall operational and design stress.[44]

Because this exclusion method can be used consistently between utilities of different sizes, staff recommends that it be used by all utilities on a going forward basis. This will allow an apples-to-apples comparison of service reliability between utilities of different sizes and will allow for the creation of Statewide reliability standards, if necessary. BHE has tentatively agreed to use this method on a going forward basis.

A comparison of historical CAIDI and SAIFI results using the Beta Method of exclusion to results using the ARP 2000 exclusion method show little variation between the two methods.[45] Thus, we do not recommend that the baselines for CAIDI and SAIFI be recalculated. Staff further recommends that this outage exclusion methodology apply to the CAIDI, SAIFI, and call answer time metrics.

[44] IEEE Std. 859-1987, Draft Guide for Electric Power Distribution Reliability Indices, (Reaff 2002).

[45] See CMP's response to Examiner's 02-20.

4. Penalty Mechanism for Service Quality Indicators

CMP recommends the same mathematical method for calculating a penalty under its ARP 2008 SQI recommendation as that used in ARP 2000, with the exception that four of the nine indicators have a higher point value and that a sliding scale be used for the value of points deducted. The sliding scale for the value of points deducted reduces penalty amounts for small misses and increases penalty amounts for larger misses. For example, for points deducted between 0.3 and .075, each point is worth $200,000. For points deducted between 0.76 and 1.25, each point is worth $400,000. This sliding scale continues up to a penalty value of $800,000 per point for point deductions over 1.75. CMP further recommends the total, annual penalty amount be increased from 3.6 million to $5 million.

Staff recommends that the Commission accept CMP's proposal to increase the maximum penalty and that the Commission reject CMP's methodology for assigning different point values to the different metrics and the sliding scale for the value of points deducted. Instead, Staff recommends that the penalty calculation methodology used in the SQI under ARP 2000 be used in ARP 2008. Under this process, each metric has the same point value and the penalty mechanism is linear, i.e., the value of each point deduction is the same. With Staff's recommendation, a small miss results in a larger penalty than under CMP's recommendation. Staff believes this is appropriate because the baselines represent "floors" and performance below those levels, even if only slightly below, is significant.

With the nine recommended metrics, each metric will have a value of 11.11 points. Staff further recommends that each point have a value of $500,000.[46] As with the methodology under ARP 2000, if the company's performance fails to meet any of the baselines, points will be deducted for each metric for which the company fails to meet the baseline. The deduction will be based on the percentage by which actual performance deviates from the baseline. For example, if actual performance deviates from the baseline by 2.5%, the deduction would be 0.27 points (11.11 X .025). No penalty will be imposed for point deductions less than 0.3 points ($150,000). Point deductions less than 0.3 for a given year shall be carried over to any subsequent year where penalties are imposed.

5. Earnings Sharing for Superior Performance

The Williams Report recommended that the Commission "consider providing CMP with an incentive for exceeding the ARP targets. For example a provision to permit rewards that would encourage CMP to go beyond managing to the ARP targets and promote continuous reliability improvement programs." Staff agrees with the Williams' recommendation. To achieve this objective, we recommend that CMP be allowed to share earnings pursuant to subsection (F) when its reliability performance, as measured by SAIDI, is at least 20% better than the established baseline.[47] The reason we recommend SAIDI is because this metric represents a

[46] This point value means the full penalty of $5 million will be incurred with a 10 point deduction. This is similar to the methodology employed under ARP 2000, where the full penalty was incurred with a nine point deduction.

[47] SAIDI stands for "System Average Interruption Duration Index" and represents the total duration of interruptions the average customer experiences over a predefined period. Mathematically, SAIDI is expressed as:

combination of CAIDI and SAIFI and is a good indicator of overall service reliability performance. We also recommend an initial baseline SAIDI of 4.28, which represents the CAIDI baseline of 2.18 multiplied by the initial SAIFI baseline of 2.10. The baseline SAIDI will change each year as the SAIFI baseline changes. To be eligible to receive the earnings sharing: 1) CMP's performance must exceed the baseline by at least 20%, which equates to a SAIDI of 3.42 for the initial SAIFI baseline; and 2) CMP cannot incur a penalty for the "Worst Performing Circuits" metric for that same year. At the 20% level, the upper-end earnings sharing band would be expanded by 100 basis points. If the Company is able to exceed SAIDI by an additional 10%, or 30% total, the Company would be eligible for an additional 50 basis point expansion (or total basis points of 150).

7. Reporting Requirements

Staff recommends that CMP file the following reports regarding service quality and reliability:

1. Bi-monthly reports. The company shall file bi-monthly reports depicting all service quality metric results with appropriate supporting data.

2. Annual Reliability Report. The company will file an annual reliability report that includes: a) service area specific analyses of service reliability; b) identification of "worst circuits" using both circuit SAIFI results and companywide SAIFI impact results; and c) SAIFI and CAIDI by circuit, regional service area, and company-wide, as well as on a pre-exclusion and post exclusion basis.

$$\frac{\sum \text{Customer Interruption Duration}}{\text{Total Number of Customers Served}}$$

In the event that an ARP is not executed as part of this proceeding, Staff recommends that CMP file a report on an annual basis that depicts its performance with regards to the nine performance measures listed above, as well as file the "Annual Reliability Report" referenced in paragraph 2 above. Invaluable data regarding CMP's service quality was collected under its previous two ARPs and staff recommends that the collection of this data continue to ensure that CMP meets its obligation to provide "reasonable an adequate service," and to allow for continued service quality trend analysis.

8. Customer Report Card

Staff recommends that CMP send a report card to each of its customers on an annual basis that describes its service quality performance for the previous year. Each August beginning in 2009, CMP will distribute an annual report card to all customers depicting the company's performance for the previous calendar year as measured by the SQI metrics. The report will list the metrics and baselines and will indicate the Company's actual performance for the previous year. Any penalties imposed pursuant to the penalty provision described above will also be reported.

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Hearing Examiner